STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	**:**	
	:	**09-0166**
Proposed general increase in natural gas rates. (Tariffs filed on February 25, 2009)	**:**	
	:	
The Peoples Gas Light and Coke Company	**:**	**09-0167**
	:	
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ORDER

January 21, 2010

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I. Introduction

A. Procedural History

On February 25, 2009, North Shore Gas Company ("North Shore" or "NS") filed with the Illinois Commerce Commission ("Commission"), pursuant to Section 9-201 of the Public Utilities Act (the "Act") (220 ILCS 5/9-201), the following revised tariff sheets: ILL. C.C. No. 17, Title Sheet and ILL. C.C. No. 17, Sheet Nos. 1, 4, 6, 8, 10, 11-12, 14-15, 18-19, 21, 26-28, 31-39, 41-52, 65-87, 89, 91, 96-100, 104, 107, 112-114, and 120-152. This tariff filing embodied a proposed general increase in gas service rates, three new Riders (one of which since has been withdrawn), and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286 of Title 83 of the Illinois Administrative Code (the "Code"), 83 Ill. Admin. Code Parts 285 and 286.

On February 25, 2009, The Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL") filed with the Commission, pursuant to Section 9-201 of the Act, the following revised tariff sheets: ILL. C.C. No. 28, Title Sheet and ILL. C.C. No. 28, Sheet Nos. 1, 2, 3-5, 7, 9, 10-11, 13-14, 16, 19-21, 24, 27, 28-29, 31-39, 41-53, 66-93, 95-100, 102-106, 110, 113, 118-120, 127, and 130-163. This tariff filing embodied a proposed general increase in gas service rates, two new Riders (one of which since has been withdrawn), and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286 of the Code.

Notices of the proposed tariff changes reflected in these rate filings were posted in North Shore's and Peoples Gas' (the "Utilities" or "Companies") business offices and published in secular newspapers of general circulation in the Utilities' respective service areas, as evidenced by publishers' certificates, in accordance with the requirements of Section 9-201(a) of the Act and the provisions of 83 Ill. Admin. Code Part 255.

The Commission issued Suspension Orders for North Shore's tariff filing on March 25, 2009, that suspended the tariffs to and including July 24, 2009, and further initiated Docket 09-0166. On July 8, 2009, the Commission issued a Resuspension Order that suspended these tariffs to, and including, January 24, 2010.

The Commission issued a Suspension Order for Peoples Gas' tariff filings on March 25, 2009, that suspended the tariffs to and including July 24, 2009, and initiated Docket 09-0167. On July 8, 2009, the Commission issued a Resuspension Order that suspended these tariffs to, and including, January 24, 2010.

On April 1, 2009, North Shore and Peoples Gas each filed motions for protective orders in each Docket, pursuant to 83 Ill. Admin. Code §§ 200.190 and 200.430.

On April 2, 2009, Staff of the Commission ("Staff") filed a motion to consolidate Dockets 09-0166 and 09-0167, pursuant to 83 Ill. Admin. Code § 200.600.

On April 3, 2009, North Shore and Peoples Gas each filed motions for case management orders in each Docket, pursuant to Section 10-101.1 of the Act and 83 Ill. Admin. Code §§ 200.190, 200.370, and 200.500.

Pursuant to notice duly given in accordance with the law and the rules and regulations of the Commission, a pre-hearing conference was held in the two Dockets before duly authorized Administrative Law Judges ("ALJs") of the Commission, at its offices in Chicago, Illinoison April 7, 2009. More than ten days prior to April 7, 2009, notice of this status hearing had been provided by the Chief Clerk of the Commission to municipalities in the Utilities' service areas, in accordance with the requirements of Section 10-108 of the Act. On April 7, 2009, at the status hearing, after addressing certain aspects of how consolidation would affect the conduct of these cases, the ALJs granted Staff's motion to consolidate.

On April 10, 2009, the ALJs issued briefing schedules for the then-pending motions for protective and case management orders.

On April 15, 2009, the Utilities moved for leave to replace the confidential and public versions of the direct testimony of Mr. Schott with public versions (removing all prior confidentiality designations).

Rulings on motions are discussed further below.

1. Petitions to Intervene

Petitions to Intervene were filed or appearances were entered on behalf of the Attorney General of the State of Illinois (the "Attorney General" or "AG"); the Citizens Utility Board ("CUB"); the City of Chicago (the "City") (collectively, CUB and the City are "CUB/City") (collectively, the AG, CUB, and the City are "AG/CUB/City or also "GCI" for "Governmental and Consumer Intervenors"); Constellation NewEnergy-Gas Division, LLC ("CNE-Gas"); Abbott Laboratories, Inc. ("Abbott") on behalf of the Illinois Industrial Energy Consumers ("IIEC"); Retail Gas Suppliers ("RGS") an ad hoc group comprised of Dominion Retail Incorporated; Interstate Gas Supply of Illinois, Inc. (Interstate Gas

Supply); Prairie Point Energy, LLC, d/b/a Nicor Advanced Energy, LLC ("NAE"); Vanguard Energy Services, LLC ("Vanguard"); and the Utility Workers Union of America, AFL-CIO, Local Union No. 18007 ("Union") (collectively, all of the foregoing parties are the "Intervenors"). All petitions were granted by the ALJs. Abbott/IIEC, after its petition was granted, filed a Motion to Withdraw, which was granted.

2. The Evidentiary Hearing

The evidentiary hearing was held August 24, 2009 through August 28, 2009, at the offices of the Commission in Chicago, Illinois. At the evidentiary hearings, the Utilities, Staff, and the Intervenors entered appearances and presented testimony. The following witnesses testified on behalf of the Utilities: Bradley A. Johnson, Treasurer North Shore Gas Company and The Peoples Gas Light and Coke Company (NS Ex. BAJ-1.0, PGL Ex. BAJ-1.0, NS-PGL Ex. BAJ-2.0 Rev., NS-PGL Ex. BAJ-3.0 Rev.); Brian M. Marozas, Manager, Planning Modeling and Contract Administration, Integrys Business Support, LLC (NS BMM 1.0, PGL BMM 1.0); Christine M. Gregor, Director Operations Accounting North Shore Gas Company and The Peoples Gas Light and Coke Company (Rev PGL CMG 1.0, NS CMG 1.0, NS & PGL CMG 2.0, NS & PGL CMG 3.0, NS & PGL CMG 4.0); David W. Clabots, Manager Sales and Revenue Forecasting, Integrys Business Support, LLC (NS & PGL DWC 1.0, NS & PGL DWC 2.0, NS & PGL DWC 3.0); Edward Doerk, Vice President, Gas Operations The Peoples Gas Light and Coke Company and North Shore Gas Company (NS ED 1.0, Rev PGL ED 1.0, NS & PGL ED 2.0, NS & PGL ED 3.0); Joylyn C. Hoffman Malueg, Rate Case Consultant – Regulatory Affairs, Integrys Business Support, LLC (NS JCHM 1.0, Rev PGL JCHM 1.0, NS & PGL JCHM 2.0, NS & PGL JCHM 3.0); James F. Schott, Vice President – Regulatory Affairs, Integrys Energy Group, Inc., The Peoples Gas Light and Coke Company, and North Shore Gas Company (Rev NS JFS 1.0, Rev PGL JFS 1.0, NS & PGL JFS 2.0, NS & PGL JFS 3.0); John Hengtgen, Rate Case Consultant, Regulatory Affairs, Integrys Business Support, LLC (NS & PGL JH 1.0, NS & PGL JH 2.0, NS & PGL JH 3.0); John J. Spanos, Vice President, Valuation and Rate Division, Gannett Fleming, Inc. (NS & PGL JJS 1.0, NS & PGL JJS 2.0); Michael A. Small, Assistant Controller Financial and Accounting Services, Integrys Business Support, LLC (NS & PGL MAS 1.0, NS & PGL MAS 2.0); Paul R. Moul, Managing Consultant, P. Moul & Associates (Rev NS PRM 1.0, Rev PGL PRM 1.0, Rev NS & PGL PRM 2.0, Rev NS & PGL PRM 3.0); Sharon Moy, Rate Case Consultant, Regulatory Affairs, Integrys Business Support, LLC (NS & PGL SM 1.0, NS & PGL SM 2.0, Rev NS & PGL SM 3.0); Valerie H. Grace, Manager, Gas Regulatory Services, Integrys Business Support, LLC (Rev NS & PGL VG 1.0, Rev NS & PGL VG 2.0, NS & PGL VG 3.0); Salvatore D. Marano, Managing Director, Jacobs Utilities Practice (Rev PGL SDM 1.0, NS & PGL SDM 2.0, Rev NS & PGL SDM 3.0); Thomas L. Puracchio, Manager, Gas Storage, Integrys Business Support, LLC (PGL TLP 1.0, PGL & NS TLP 2.0, PGL & NS TLP 3.0, NS & PGL TLP 4.0); Richard Dobson, Manager, Gas Supply, The Peoples Gas Light and Coke Company and North Shore Gas Company, Integrys Business Support, LLC (Rev NS & PGL RD 1.0, NS & PGL RD 2.0); John McKendry, Senior Leader, Gas Transportation Services, The Peoples Gas Light and Coke Company and North Shore Gas Company, Integrys Business Support, LLC (NS & PGL JM 1.0, NS & PGL JM 2.0); James C. Hoover, Director, Compensation, Integrys Energy Group, Inc. (NS & PGL

JCH 1.0, NS & PGL JCH 2.0, NS & PGL JCH 3.0); Steven M. Fetter, President, Regulation UnFettered (NS & PGL SMF 1.0, NS & PGL SMF 2.0); Alan Felsenthal, Managing Director, Huron Consulting Group (NS & PGL AF 1.0, NS & PGL AF 2.0, NS & PGL AF 3.0); and Christine Phillips, Manager, Benefits Accounting, Integrys Business Support, LLC (NS & PGL CMP 1.0, NS & PGL CMP 2.0).

The following witnesses testified on behalf of Staff: Dianna Hathhorn, Accountant, Accounting Department Financial Analysis Division (1.0, Rev 15.0); Bonita A. Pearce, Accounting Department, Financial Analysis Division (2.0 & 16.0); Mike Ostrander, Accountant, Accounting Department, Financial Analysis Division (3.0 & 17.0); Mary H. Everson, Accountant, Financial Analysis Division (4.0, 18.0 & 18.1); Richard W. Bridal II, Accountant, Accounting Department, Financial Analysis Division (5.0 & 19.0); Larry H. Wilcox, Accountant, Financial Analysis Division (6.0, 20.0 & 20.1); Michael McNally, Senior Financial Analyst, Finance Department, Financial Analysis Division (Rev 7.0 & 21.0); Sheena Kight-Garlisch, Senior Financial Analyst, Finance Department, Financial Analysis Division (8.0, 22.0 & 22.1); Peter Lazare, Senior Economic Analyst, Rates Department; Financial Analysis Division (9.0 & 9.1); Cheri L. Harden, Rate Analyst, Rates Department; Financial Analysis Division (10.0 & 24.0); Christopher Boggs, Rate Analyst, Rates Department, Financial Analysis Division (11.0, 25.0 & 25.1); David Sackett, Economic Analyst, Policy Program, Energy Division (Rev 12.0R & 26.0); Brett Seagle, Engineering Department, Energy Division (13.0 & 27.0); Harold L. Stroller, Director, Energy Division (14.0 & 28.0); Darin Burk, Pipeline Safety Program Manager, Energy Division (23.0); and David Rearden, Policy Program, Energy Division (29.0).

GCI's witnesses were David J. Effron, Consultant (1.0 & 4.0); Scott J. Rubin, Consultant, (Rev 2.0, Rev 3.0, Rev 5.0, Rev 6.0) except that the City did not sponsor the direct and rebuttal testimony of Mr. Rubin on behalf of AG-CUB only and the City did not sponsor the rebuttal testimony of Mr. Effron on behalf of AG-CUB.

CUB-City's witnesses were Edward C. Bodmer, Consultant (1.0, 3.0, 5.0 Admitted 9/14/09); and Christopher C. Thomas, Director of Policy, CUB (Rev 2.0 & Rev 4.0).

CNE Gas' witness was Lisa A. Rozumialski, Manager of Gas Operations, CNE Gas (1.0, 2.0 & 3.0).

RGS' witness was James L. Crist, President, Lumen Group (1.0 & Rev 2.0).

All parties were given the opportunity to cross-examine witnesses. On September 14, 2009, the ALJs marked the record "Heard and Taken".

3. Rulings on Motions

On April 7, 2009 a Status hearing was held, as stated above. The ALJs granted Staff's motion to consolidate these Dockets.

On April 17, 2009, the ALJs issued an order granting the Utilities' motion to remove the confidentiality designations from the direct testimony of Mr. Schott.

On April 27, 2009, the ALJs issued an Order for a Case Management Plan and Schedule in these dockets. Also on April 27, 2009, and after considering all of the parties' arguments, the ALJs entered a Protective Order for these Dockets.

On July 22, 2009 the ALJs granted the Utilities' request for Leave to File Revised Rebuttal Testimony Instanter.

On August 25, 2009 the ALJs denied Staff's August 21, 2009, motion to strike portions of the Surrebuttal testimony of Mr. Marano.

On August 25, 2009 the ALJs granted Staff's motion to strike a portion of the surrebuttal testimony of Mr. Moul.

On October 6, 2009 the ALJs granted the Union's September 29, 2009, motion for leave to file an Initial Brief instanter.

4. Post-Hearing Briefs

On September 29, 2009, the Utilities, Staff, the AG, the City, CUB, CUB/City, CNE-Gas, RGS, and the Union each filed an Initial Brief ("Init. Br.").

On September 29, 2009 , the City filed an Init. Brief on the proposed infrastructure rider separate from CUB/City.

On October 5, 2009, per the direction of the ALJs, the Utilities submitted a draft Proposed Order and Staff, CNE-Gas, the City, CUB/City, RGS, and the AG submitted draft position statements.

On October 9, 2009, CNE-Gas, RGS, CUB/City, the City, Staff, the AG and the Utilities each filed Reply Briefs ("Rep. Br.").

On November 6, 2009, the ALJs issued their Proposed Order.

On November 24, 2009, Briefs on Exceptions ("BOEs") were filed by the Utilities, CNE-Gas, RGS, CUB/City, the AG and Staff. On December 4, 2009, Reply Briefs on Exceptions ("RBOEs") were filed by Staff, CUB/City, the AG, Utilities, and RGS.

The record was re-opened by the ALJs on December 7, 2009 and re-closed on December 11, 2009, with no action taken.

This Order considers all of the positions and arguments set out in the exceptions briefs and reply briefs listed above.

B. Nature of Operations

1. North Shore

North Shore is a local distribution company engaged in the business of transporting, purchasing, storing, distributing and selling natural gas at retail to approximately 158,000 residential, commercial, and industrial customers within fifty-four communities in Lake and Cook Counties, Illinois. NS Ex. JFS-1.0 at 5; NS Ex. ED-1.0 at 3. North Shore employs approximately 170 people. NS Ex. JFS-1.0 at 5. North Shore is a wholly owned subsidiary of Peoples Energy Corporation, which in turn is a wholly owned subsidiary of Integrys Energy Group, Inc. ("Integrys"). *Id*.

North Shore's distribution system consists of approximately 2,280 miles of gas distribution mains. NS Ex. ED-1.0 at 3. North Shore owns approximately 95 miles of gas transmission lines. *Id*. Its distribution system is most commonly operated at a pressure of 45 pounds per square inch ("PSI"), while the transmission system operates at a pressure of 250 PSI. *Id*. While North Shore does not own any storage fields, it does purchase storage services from Peoples Gas, pursuant to a storage services agreement that was approved by the Commission. *Id*. In addition, North Shore owns a liquid propane production facility used for peaking purposes. *Id*.

The physical configuration of North Shore's system is a dispersed/multiple city-gate, integrated transmission/distribution and multi pressure-based system. NS Ex. ED-1.0 at 3. It is designed to provide gas service to all customers entitled to be attached to the system, to deliver volumes of natural gas to all sales and transportation customers, and to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day. *Id*. at 4.

2. Peoples Gas

Peoples Gas is a local distribution company engaged in the business of transporting, purchasing, storing, distributing, and selling natural gas at retail to approximately 850,000 residential, commercial, and industrial customers within the City of Chicago. PGL Ex. JFS-1.0 at 6; PGL Ex. ED-1.0 at 3. This service territory covers an area of about 237 square miles and has a population of approximately three million people. PGL Ex. JFS-1.0 at 6. Peoples Gas employs approximately 1,110 people, all within the City of Chicago. *Id*. Peoples Gas is a wholly owned subsidiary of Peoples Energy Corporation, which in turn is a wholly owned subsidiary of Integrys. *Id.*

Peoples Gas' distribution system consists of approximately 4,025 miles of gas distribution mains. PGL Ex. ED-1.0 at 4. It owns approximately 425 miles of gas transmission lines. *Id.* The distribution system is most commonly operated at a pressure range of 0.25 to 25 PSI, while the transmission system operates at pressures up to 300 PSI or more. *Id.* Peoples Gas also owns a storage field, Manlove Field. *Id.*

The physical configuration of Peoples Gas' system is a dispersed/multiple city gate, integrated transmission/distribution and multi pressure-backed system. PGL Ex. ED-1.0 at 4. It is designed to provide gas service to all customers entitled to be attached to the system, to deliver volumes of natural gas to all sales and transportation customers, and to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day. *Id.*

II. Test Year (Uncontested)

The Utilities each proposed calendar year 2010, the twelve months ending December 31, 2010, as their future test year. PGL Ex. SM-1.0 at 4; NS Ex. SM-1.0 at 4. The 2010 test year data were based on the Utilities' forecasted 2010 revenues, expenses, and rate base items, subject to appropriate adjustments. PGL Ex. SM-1.0 at

5, 6; PGL Ex. CMG-1.0 Rev. at 5; NS Ex. SM-1.0 at 5, 6; NS Ex. CMG-1.0 at 5. No party contested the proposed test year. The Commission approves the test year as reasonable.

III. Revenue Requirement

A. North Shore

North Shore is proposing a revenue requirement of $83,305,000, an increase of $18,105,000 over current rates. NS-PGL Ex. SM-3.0 Rev. at 3; NS-PGL Ex. SM-3.1N at Sched. C-1, line 3. This proposed revenue requirement reflects that North Shore agreed with or accepted, in whole or in part, numerous Staff- and intervenor-proposed adjustments and updated certain items. NS-PGL Ex. SM-3.0 Rev. at 2, 3, 4; NS-PGL Ex. SM-3.2N at Sched. C-2; NS-PGL Ex. JFS-3.0 at 6; NS-PGL Ex. JFS-3.1

With the adjustments adopted in the Order, North Shore's revenue would increase by $12,974,000.

B. Peoples Gas

Peoples Gas is proposing a revenue requirement of $574,038,000 an increase of $113,178,000 over current rates. NS-PGL Ex. SM-3.0 Rev. at 3; NS-PGL Ex. SM-3.1P at Sched. C-1, line 3. The proposed revenue requirement reflects that Peoples Gas agreed with or accepted, in whole or in part, numerous Staff- and intervenor-proposed adjustments and updated certain items. NS-PGL Ex. SM-3.0 Rev. at 2, 3, 4; NS-PGL Ex. SM-3.2P at Sched. C-2; NS-PGL Ex. JFS-3.0 at 6; NS-PGL Ex. JFS-3.1.

With the adjustments adopted in the Order, Peoples Gas' revenue would increase by $63,601,000.

IV. Rate Base

A. Overview

1. North Shore

North Shore's surrebuttal presented a rate base of $179,927,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part, certain updates, and the correction of certain prior calculation errors.

Staff recommends the Commission adopt a rate base of $177,867,000.

2. Peoples Gas

Peoples Gas' surrebuttal presented a rate base of $1,300,750,000, reflecting adjustments proposed by Staff and intervenors that the utility accepted in whole or in part, certain updates, and the correction of certain prior calculation errors.

Staff recommends the Commission adopt a rate base of $1,170,346,000.

B. Uncontested Issues (All subjects relate to North Shore and Peoples Gas unless otherwise noted)

1. Natural Gas Prices for Purposes of Cushion Gas (Peoples Gas), Gas in Storage, and Cash Working Capital

a) The Record

The Utilities, Staff, AG, and CUB agree that the natural gas prices for the purposes of cushion gas (Peoples Gas only), gas in storage, and cash working capital should be updated based upon data in the Utilities' August 2009 Gas Charge filings, the most recent data in the evidentiary record. NS-PGL Ex. CMG-3.0 at 2-3; NS-PGL Ex. JH-3.0 at 4, 5, 6; AG-CUB Ex. 4.0 at 4; Staff Ex. 27.0 at 13-17; Tr. at 914-915.

b) Commission Analysis and Conclusion

The Commission finds that the use of the gas prices based on data in the Utilities' August 2009 Gas Charge filings to update the natural gas prices for purposes of cushion gas (Peoples Gas only), gas in storage, and cash working capital to be reasonable.

2. Plant

a) Original Cost Determinations as to Plant Balances as of 12/31/07

(1) The Record

Utilities witness Hengtgen's proposal that the Commission's final Order include an original cost determination as to each utility is uncontested. Mr. Hengtgen proposed that the Order make such determinations, pursuant to 83 Ill. Adm. Code Part 510 and its Appendix A, regarding Peoples Gas' and North Shore's Gross Utility Plant balances as of December 31, 2007. PGL Ex. JH-1.0 at 17-18; NS Ex. JH-1.0 at 14.

Staff witness Bridal agreed that such a determination should be included in the Commission's final Order. He recommended that the Order state in part:

> It is further ordered that the $2,525,147,000 original cost of plant for Peoples Gas at December 31, 2007, as reflected on the Company's Schedule B-5, Page 1 of 2, Line 14, Column F; and the $398,983,000 original cost of plant for North Shore at December 31, 2007, as reflected on the Company's Schedule B-5, Page 1 of 2, Line 12, Column F, are unconditionally approved as the original costs of plant.

Staff Ex. 5.0 at 8-9. The Utilities agreed. NS-PGL Ex. JH-2.0 at 17–18. No witness disagreed.

In its briefs, however, Staff adjusted its original cost determination to reflect Staff's proposed adjustment for capitalized incentive compensation costs that the Commission disallowed in the Utilities' prior rate case. Staff proposes to reduce Peoples Gas original cost of plant by $166,000 and North Shore's by $27,000

(2) Commission Analysis and Conclusion

The Commission accepts Staff's and the Utilities' recommendation to have the final order include original cost determinations pursuant to 83 Ill. Adm. Code 510 and Appendix A thereto. On the basis of the evidence and arguments, the Commission approves $2,524,981,000 and $398,956,000, as the original cost of plant in service for Peoples Gas and North Shore, respectively, as of December 31, 2007. These balances consist of the balance from each Utility's Schedule B-5 (Utilities' Section 285.2030 Schedule B-5, p. 1 of 2, Line 14, Column F) reduced by capitalized incentive compensation costs the Commission disallowed in each Utility's prior rate case. Staff Ex. 15.0, Sch. 15.7 P and 15.7 N, at 5, line 4.

b) Capitalized Union Wages

(1) The Record

Staff witness Hathhorn proposed to reduce the rate bases of North Shore and Peoples Gas by $15,000 and $98,000, respectively, to correct an error in calculating test year union wages at the non-union rate. Staff Ex. 1.0, Sched. 1.2P and 1.2N, Sched. 1.4P and 1.4N. AG-CUB-City and the Utilities agreed. AG-CUB/City Ex. 1.0 at 17; NS-PGL Ex. SM-2.0 at 4, 5; NS-PGL Ex. JH-2.0 at 4. No witness opposed Staff's adjustments.

(2) Commission Analysis and Conclusion

The Commission finds that the adjustments to reduce the rate bases of North Shore and Peoples Gas by $15,000 and $98,000, respectively, are appropriate. Therefore, each of these amounts is approved.

c) Capitalized Civic, Political, and Related Activities

(1) The Record

Staff's proposal to reduce the rate bases of North Shore and Peoples Gas by $6,000 and $14,000, respectively, for expenses associated with lobbying and related activities is uncontested. Staff Ex. 6.0 at 6-7; NS-PGL Ex. SM-2.0 at 5; NS-PGL Ex. JH-2.0 at 4.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's adjustments to reduce the rate bases of North Shore and Peoples Gas by $6,000 and $14,000, respectively, for expenses associated with lobbying and related activities to be appropriate and uncontested. Thus, these adjustments are approved.

d) Net Dismantling

(1) The Record

North Shore and Peoples Gas proposed to change the accounting for the net dismantling portions, *i.e.*, the cost of removal of an asset net of salvage, of their Depreciation Reserves from a cash basis to an accrual basis, effective January 1, 2010. NS Ex. CMG-1.0 at 20; PGL Ex. CMG-1.0 (Rev.) at 21-22. No party opposed that proposal. At one point, there was a disagreement between Staff and the Utilities regarding an aspect of the net dismantling computations, but, after the Utilities presented further testimony, Staff accepted the Utilities' approach. NS-PGL Ex. SM-2.0 at 5-6; Staff Ex. 18.0 at 3.

North Shore and Peoples Gas request that the final Order contain language expressly approving the proposal, so that it will be clear that it has been approved.

(2) Commission Analysis and Conclusion

The Commission approves as reasonable and appropriate the Utilities' proposal.

e) Gathering System Pigging Project (Peoples Gas)

(1) The Record

One of the many Peoples Gas projects expected to enter service before the end of the test year is the Gathering System Pigging Project, in which approximately $500,000 will be spent in 2009. NS-PGL Cross Effron Ex. 29. Staff witness Seagle initially objected to the inclusion of this project in rate base, but after receiving further information he agreed that the project was properly included in Peoples Gas' rate base. Tr. at 911.

(2) Commission Analysis and Conclusion

The Commission finds the Gathering System Pigging Project to be appropriately included in rate base because it is prudent, reasonable, and used and useful.

f) Cushion Gas – Recoverable (Peoples Gas)

(1) The Record

There is no dispute as to the amount of recoverable cushion gas to include in Peoples Gas' rate base. As discussed above, the parties also agreed to the price to be used. Thus, Peoples Gas' recoverable cushion gas additions should be valued at $349,000 and $381,000 for 2009 and 2010, respectively. *See* NS-PGL Ex. JH-3.3P at 1.

(2) Commission Analysis and Conclusion

The Commission finds that the use of the gas prices based on data in the Utilities' August 2009 Gas Charge filings to update the natural gas prices for purposes of recoverable cushion gas (Peoples Gas only) to be reasonable, as stated above. Thus, Peoples Gas' recoverable cushion gas additions valued at $349,000 and $381,000 for 2009 and 2010, respectively, are approved.

g) Cushion Gas – Non-recoverable (Peoples Gas)

(1) The Record

There is no dispute as to the amount of non-recoverable cushion gas. Thus, Peoples Gas' non-recoverable cushion gas additions should be valued at $6,628,000 and $7,236,000 for 2009 and 2010, respectively. *See* NS-PGL Ex. JH-3.3P at 1, line 3.

(2) Commission Analysis and Conclusion

The Commission finds that the use of the gas prices based on data in the Utilities' August 2009 Gas Charge filings to update the natural gas prices for purposes of non-recoverable cushion gas (Peoples Gas only) to be reasonable. Thus, Peoples Gas' non-recoverable cushion gas additions valued at $6,628,000 and $7,236,000 for 2009 and 2010, respectively, are approved.

h) Capitalized Savings Plan Costs

(1) The Record

AG/CUB/City witness Effron initially proposed to capitalize a portion of the Savings and Investment Plan cost based on the Utilities' responses to data requests AG 3.21 and AG 3.67. AG/CUB/City Ex. 1.0 at 23. After receiving further information, Mr. Effron withdrew his adjustment as no longer necessary. AG-CUB Ex. 4.0 at 11.

(2) Commission Analysis and Conclusion

The Commission finds that the withdrawal of the adjustment to capitalize a portion of the Savings and Investment Plan cost to be uncontested, and the proposal is not necessary. Therefore, we approve the withdrawal.

3. Accumulated Reserve for Depreciation and Amortization - Inventory Reclassification

a) The Record

Staff witness Hathhorn proposed adjustments to the Depreciation Reserve, Gas in Storage (as to Peoples Gas), and Accumulated Deferred Income Taxes related to inventory reclassification. The Utilities accepted those adjustments. NS-PGL Ex. JH-2.0 at 4; NS-PGL Ex. JH-2.2N at Sched. B-2;. NS-PGL Ex. JH-2.2P at Sched. B-2.

b) Commission Analysis and Conclusion

The Commission finds that Staff's adjustments to the Depreciation Reserve, Gas in Storage (as to Peoples Gas), and Accumulated Deferred Income Taxes related to inventory reclassification to be reasonable and uncontested. Therefore, these adjustments are approved.

4. Materials and Supplies Correction

a) The Record

The Utilities corrected an error in the original level of materials and supplies. NS-PGL Ex. JH-3.0 at 4-5. The corrected levels are shown on line 5 of the Revised Schedule B-1 for each of the Utilities, NS-PGL Ex. JH-3.1N and Ex. JH-3.1P.

b) Commission Analysis and Conclusion

The Commission finds that the corrected levels of materials and supplies to be reasonable. Therefore, these amounts are approved.

5. Gas in Storage

a) The Record

The Utilities corrected an error in the original Gas in Storage calculations, and used the final updated figures for the price of natural gas. NS-PGL Ex. JH-3.0 at 5-6. The uncontested amounts for Gas in Storage are shown on line 6 of the Revised Schedule B-1 for each of the Utilities, in NS-PGL Ex. JH-3.1N and Ex. JH-3.1P.

b) Commission Analysis and Conclusion

The Commission finds that the corrected original Gas in Storage calculations, and using the final updated figures for the price of natural gas, discussed above, to be reasonable. Therefore, these amounts are approved.

6. Methodology to Account for Amortization of Remaining Pre-Merger Unamortized Costs

a) The Record

In order to refine the methodology for amortizing the remaining pre-merger unamortized costs, the Utilities proposed to separately identify the remaining pre-merger net regulatory assets for pension and other welfare benefit plans and amortize those costs using a straight-line amortization based on the average remaining service lives of the underlying benefit plans, effective January 1, 2010. PGL Ex. CMG-1.0 at 20; NS Ex. CMG-1.0 at 19. This change (1) will eliminate the need for the actuary to prepare a separate accounting valuation; and (2) will reflect an additional decrease to pension costs and an additional increase to welfare costs in the test year. *Id.* No witness objected to this change. North Shore and Peoples Gas request that the final Order contain language expressly approving the proposal, so that it will be clear that it has been approved.

b) Commission Analysis and Conclusion

The Commission finds that the Utilities' proposal to separately identify the remaining pre-merger net regulatory assets for pension and other welfare benefit plans and amortize those costs using a straight-line amortization based on the average remaining service lives of the underlying benefit plans to be uncontested and appropriate. Thus, the Commission approves this change in methodology.

C. Plant

1. Forecasted Plant Additions

a) Utilities

The Utilities note that from the time of their initial filing in February 2009, their forecasted plant additions have changed in response to the economy. In their direct testimony, the Utilities announced that they were adopting cost control measures that would be reflected in their rebuttal testimony. In response to data requests before their rebuttal testimony, the Utilities stated in March 2009 a reduced level of plant additions.

However, as the Utilities refined their budgets, the forecast plant additions changed again, increasing slightly from those reduced levels. In response to subsequent data requests, in July 2009, the Utilities set out another revised forecast. The main driver of the July 2009 revisions was changes in high priority public improvements projects. For example, on June 17, 2009, final approval was obtained for the $8.5 million to be spent in 2010 on the U.S. Route 45 and Delaney Road public improvement projects. NS-PGL Cross Effron Ex. 27. The July 2009 revised forecasted plant additions have not changed and are the most accurate forecasts of the plant additions. NS-PGL Ex. ED 3.0 at 3.

According to the Utilities, Mr. Effron's continued use of the interim forecast numbers from March 2009 is not reasonable, not supported by any evidence, and would deny the Utilities' recovery for projects that are actually in their approved budgets and will be serving customers. The Utilities argue that his cross-examination showed that he was presented with detailed, updated supporting information and that he has no basis for advocating use of older data instead of the latest information. Tr. at 786 – 789.

b) AG

The gross utility plant included in rate base is the forecasted average plant balance in 2010, the test year in this case. AG/CUB/City Ex. 1.0 at 5. The Companies began with the actual balances of plant as of June 30, 2008 and then adjusted those balances for forecasted additions to, and retirements from, plant for the last six months of 2008 and calendar years 2009 and 2010. *Id.*

In his direct testimony, AG/CUB/City witness Effron stated that the actual December 31, 2008 actual balance of plant should be used as the starting point for the forecast of 2010 test year plant. *Id.* Second, and more importantly, Mr. Effron testified that given the Companies' statements that they would be substantially reducing their forecasts of capital additions for both 2009 and the 2010 test year, due in part to the economic slowdown, those reductions should be taken into account in the determination of the test year rate bases. In determining his proposed adjustment to forecasted plant, Mr. Effron began with the actual plant as of December 31, 2008, and then incorporated the Utilities' latest updated forecast of capital additions in 2009 and 2010, based on the Utilities' response to Staff Data Requests PGL MHE 12.01 and NS MHE 12.01.

With these modifications to the forecast of plant additions in 2009 and 2010, the average balance of gross utility plant for Peoples Gas in the 2010 test year is $2,549,045,000. This is $116,343,000 less than the gross utility plant included in rate base by Peoples Gas. *Id.* at 6-7.

For North Shore, with Effron's modifications to the forecast of plant additions in 2009 and 2010, the average balance of gross utility plant in the 2010 test year is $393,430,000. *Id.* This is $5,374,000 less than the gross utility plant included in rate base by North Shore.

Upon the filing of their rebuttal case, the Company opined that it was updating its forecast of plant additions yet again. Mr. Effron, in his rebuttal testimony, noted that there already have been several changes to the forecasts of plant additions in 2009 and

2010. He stated that at this time, he has no reason to believe that the 2009 and 2010 forecasts referenced by Mr. Doerk and Mr. Puracchio are any more accurate than the 2009 and 2010 forecasts in the responses to Staff Data Request MHE 12.01. Therefore, his schedules reflect the forecasts of plant additions in the responses to Staff Data Request MHE 12.01, and adjusted the 2010 test year plant included in rate base in the rebuttal exhibits of Mr. Hengtgen accordingly.

Utilities witness Doerk's surrebuttal statement that since the last update, revisions were made to the capital budget to reflect additions of "high priority public improvements and system improvements" never disclosed what these "high priority" projects were. According to the AG, there simply is no basis to hold the newest NS/PGL plant additions forecast more reliable than its second update to the original forecast.

Accordingly, Mr. Effron's proposed adjustments to plant additions should be adopted by the Commission.

c) Staff

Staff asserts that the Commission should accept the revised level of forecasted plant additions the Companies proposed in rebuttal. After reviewing the Companies' responses to data requests related to the revised level of forecasted plant additions, Staff witness Everson testified that she had no objection to the Companies' revised levels of forecasted plant additions. Staff Ex. 18.0 at 2-3.

d) Commission Analysis and Conclusion

Based on the Companies' explanations and details supporting the changes in the specific projects, the Commission adopts the Utilities' proposed forecasted plant additions. Specifically, the record evidence showing the approval of the public improvement projects cited by the Utilities supports this finding. We also note that Staff witness Everson was satisfied with the Utilities' support of their most recent forecasts. The Commission finds it appropriate to use the most recent information available because it was sufficiently supported and, accordingly, the Commission approves the Utilities' forecasted plant additions

2. Gathering System Phase 2 Project (Peoples Gas)

a) Peoples Gas

Peoples Gas' only gas storage facility is Manlove Field. Gas is injected underground into the former water-bearing aquifer, so that it can be extracted when needed to serve customers. An integral component of the field is a network of pipes that are used when extracting gas from the field. This gathering system at Manlove has been used to serve customers for many years.

Peoples Gas has identified reasons to modernize the system and replace aging and corroding pipes. One important maintenance tool is "pigging," which involves sending a large object, known as a pig, through the pipes, which serves to clean them and de-water them. NS-PGL Ex. TLP-2.0 at 2. One purpose of the Gathering System Replacement Project is to have modern, pig-compatible pipes. PGL Ex. TLP-1.0 at 9.

Second, the existing pipes have been developing corrosion, which has reliability implications. NS-PGL Ex. TLP-3.0 at 2-3.

Peoples Gas states that this is a multi-year project that will cost tens of millions of dollars. PGL Ex. TLP-1.0 at 8; PGL Ex. ED-1.1. $1,500,000 is being spent in 2009 for the engineering study that will help chart which pipes will be replaced in which years. NS-PGL Ex. TLP-2.0 at 6; NS-PGL Ex. TLP-3.0 at 4. Staff does not contest the investment for the engineering study (Staff calls the 2009 expenditures "Phase 1"). Peoples Gas has forecasted an additional $5.7 million to be spent in 2010. NS-PGL Ex. TLP-2.0 at 6; NS-PGL Cross Effron Ex. 29. Staff has proposed to disallow that investment from rate base.

In testimony, Staff witness Seagle presented two arguments, neither of which the Company believes warrants the disallowance. First, Mr. Seagle testified that Peoples Gas had not shown that the replacement pipes would be used and useful in serving customers. Staff Ex. 13.0 at 7-8. The Company believes that the evidence shows otherwise. The replacement pipes will have the same function as the pipes currently in use, and such pipes are critical to the operation of the storage field. Staff cites Section 9-212 of the Act. 220 ILCS 5/9-212. The Company says it does not apply to this type of plant.

Second, Mr. Seagle said that, as of the time of his rebuttal testimony, the engineering study was not far enough along to say whether the project would really proceed. Staff Ex. 27.0 at 12-13. In response, Peoples Gas presented testimony from Mr. Puracchio and from the engineering consultant that is performing the study. Although the overall scope of the project – for example, whether the project will last ten years or only eight – is not yet known, based on the analyses that have already been performed, it is clear that the forecasted 2010 work will need to proceed or be accelerated. NS-PGL Ex. TLP-3.0 at 4-5; NS-PGL Ex. SDM-3.0 at 15-16.

Staff also argued that because Peoples Gas provided an update that reduced the amount expected to be invested in the test year and thus included in its final revised rate base that somehow supported the view that the project is speculative. *Id*. at 13. The Company argues that the reduced amount of $5.7 million that Peoples Gas included in its final revised rate base is more than amply supported by the evidence in the record, and the fact that Peoples Gas provided that updated reduced amount is no reason to find that the project is speculative. Staff's proposed disallowance should not be adopted.

b) Staff

Peoples Gas' proposed Gathering System Replacement project is a two-phase project. Phase 1 involves an engineering study to assess the existing system and the development of an optimized replacement plan. Staff does not dispute Peoples Gas' request to include the cost of Phase 1 of the project in its rates.

Phase 2 of the project involves either the complete or partial replacement of the gathering system at Peoples Gas' Manlove storage field. Peoples Gas also explained that it is only after Phase 1 of the project is completed will it prepare a cost benefit analysis and business case for the project and then seek approval for any expenditures from the Board of Directors. Peoples Gas also indicated under either option (partial or complete replacement), the test year costs would be the same and that the project may take up to 10 years to complete. PGL Ex. TLP-1.0 at 9-10.

Staff argues that Peoples Gas failed to provide sufficient information to demonstrate that Phase 2 of the project would be prudently incurred and used and useful. Further, Staff noted that Peoples Gas failed to demonstrate that it is pursuing this project prior to the end of the 2010 test year. Also, Staff noted that Peoples Gas' reduction of the test year cost estimates associated with the project supports Staff's concerns that the project is speculative. Therefore, Staff recommended the removal of Peoples Gas' requested costs associated with Phase 2 from its requested rates.

Regarding Staff's first concern, Staff witness Seagle noted that Peoples Gas must meet the requirements of Section 9-211 of the Public Utilities Act ("Act") to include the cost of Phase 2 of its Manlove gathering system project into its proposed rates. Staff Ex. 13.0 at 8. Specifically, this section of the Act states as follows:

> The Commission, in any determination of rates or charges, shall include in a utility's rate base only the value of such investment which is both prudently incurred and used and useful in providing service to public utilities customers.

220 ILCS 5/9-211. He further noted that the Act provides a definition of used and useful in Section 9-212 of the Act *I* which states:

> A generation or production facility is used and useful only if, and only to the extent that, it is necessary to meet customer demand or economically beneficial in meeting such demand. 220 ILCS 5/9-212.

Finally, Mr. Seagle pointed out that in prior cases the Commission has provided guidance regarding the requirements for prudence. *Id*. at 9. Namely, in Docket 88-0142, the Commission defined prudence as follows:

> Prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made. In determining whether a judgment was prudently made, only those facts available at the time judgment was exercised can be considered. Hindsight review is impermissible.

Docket 88-0142, Order February 5, 1992 at 25-26.

In other words, Peoples Gas must demonstrate the project is necessary or economically beneficial to customers as well as the prudence of its decision-making associated with the project. However, the Company itself admits that the cost benefit analysis and business case that it expects to demonstrate that the project will be prudent and used and useful will not be developed until 2009. PGL Ex. TLP-1.0 at 10. While Peoples Gas admits these documents are required for it to demonstrate to its Board of Directors that expenditures should be made on the project, Peoples Gas failed to provide these documents for the record in this proceeding for the Commission to review and make a decision on the prudence and used and usefulness of the project.

Peoples Gas was unable to provide such documentation because it must wait on the result of its Phase 1 engineering study to determine the scope and need for Phase 2 of the project. Phase 1 of the project was only recently initiated in July 2009 with a project kick-off meeting with the selected engineering firm the week of July 13, 2009, and Peoples Gas projects a completion date of November 2009. NS-PGL TLP-2.0 at 5.

While Staff does not disagree that the existing system cannot accommodate pipeline pigs, Peoples Gas failed to demonstrate the gathering system corrosion has reached a point that the gathering system at Manlove needs replacement or that the gathering system has reached the end of its useful life. Instead, Staff witness Seagle noted the only support that Peoples Gas provided for its claims was a slide show presentation where it made unsubstantiated claims of increased safety and reliability associated with the project. In short, Peoples Gas did not provide to the record any documentation regarding how the replacement project was needed or will benefit its ratepayers. Staff Ex. 13.0 at 11.

Regarding Staff's second concern that Peoples Gas failed to demonstrate that it is pursing this project prior to the end of the 2010 test year, Mr. Seagle noted that the absence of a completed engineering study (Phase 1 of project) and the absence of a cost benefit analysis or business case for the project demonstrates that the Company cannot produce a definitive timeline for the project. Mr. Seagle noted that the recent issuance of the engineering study RFP (Phase 1) indicated Peoples Gas was still at the starting point in determining what, if anything, needs replacement at the Manlove storage field. Staff Ex. 13.0 at 11-12.

Peoples Gas has provided a proposed timeline for Phase 2 of the project that indicates it intends to start work on the gathering system in early 2010. However, the Company admits that the determination of the length of time needed for the completion of the project and the approximate start date of the project requires the completion of the engineering study (Phase 1). NS-PGL Ex. TLP-2.0 at 6. The Company also admitted that until the completion of the engineering study, Phase 1, there will be some uncertainty involved in pursuing this addition, but Peoples Gas is confident that enough of the gathering system needs replacement that it begin making its projected investments to replace at least a portion of the gathering system in 2010. *Id.* at 4-5.

Peoples Gas also admits until the completion of engineering study (Phase 1), it does not know the full scope of the project, which includes if the project is needed in 2010 or not, and it cannot conduct a cost benefit analysis or business case for the project. Due to the potential monetary investment needed for the proposed project, Peoples Gas requires all of this information to seek approval for any expenditure from the Board of Directors. However, Peoples Gas has not completed any of the required studies nor has Peoples Gas received Board approval for any expenditure associated with Phase 2 of the project. In short, Peoples Gas has provided nothing but its good intentions to support that it will incur any costs or pursue Phase 2 of this project in the 2010 test year.

Regarding Staff's other concern that Peoples Gas reduction of costs associated with Phase 2 of the Gathering System Replacement project supported a conclusion that the project is speculative in nature, Staff notes that given the lack of supporting documentation regarding the scope and timing of the project, any cost projections are pure conjecture and do not support Peoples Gas' request to include the Phase 2 costs within its requested rates.

Further, Peoples Gas assumption that it will acquire Board of Director approval for Phase 2 of the project in either late 2009 or early 2010 is pure conjecture. Even under the assumption that the engineering study (Phase 1) indicates a portion of the gathering system at Manlove needs replaced and Peoples Gas can develop a cost benefit analysis and business case to support the replacement, Peoples Gas' Board of Directors could still elect to defer the project to a later period.

In short, Peoples Gas cannot project a reasonable estimate for the overall cost or extent of the project, nor can it guarantee its Board of Directors will provide immediate approval of the project assuming some replacement of the gathering system is necessary. Given the unknown nature of the project and its costs, Staff cannot support including any estimated costs associated with this project in the test year.

c) Commission Analysis and Conclusion

The Commission finds that the Company has failed to provide sufficient evidence to include Phase 2 in its rate base. In particular, the Commission notes that the Company just started Phase 1 and, thus, there is no support for the amounts proposed to be included. The results of the Phase 1 engineering study, which will show the extent of the needed replacement, are not available. Without this evidence, the Commission cannot say to what extent it will be prudent to replace these existing pipes. Although not controlling, we also note that unlike the forecasted plant additions issue, no approval has been received from the Company's Board of Directors. The Commission cannot include in rate base a project of unknown magnitude and need.

3. Capitalized Incentive Compensation –

This issue is addressed below.

4. Capitalized Non-Union Base Wages

This issue is addressed below.

D. Reserve for Accumulated Depreciation and Amortization (Uncontested Except for Derivative Adjustments from Contested Adjustments)

1. The Record

North Shore and Peoples Gas propose to change the accounting for the net dismantling. This proposal is uncontested and is discussed above.

Staff and intervenors have not proposed any independent adjustments to the Depreciation Reserve. All of their proposed adjustments to the Reserve are derivative of their proposed adjustments to other items.

2. Commission Analysis and Conclusion

Accordingly, apart from the net dismantling point, the Depreciation Reserve should include the appropriate derivative calculations. There is no dispute regarding how those calculations are performed. The Commission approves the levels set forth in the Utilities' surrebuttal testimony, subject to the derivative impacts of the Commission's rulings on the applicable contested adjustments discussed elsewhere in this Order.

E. Cash Working Capital

1. Pass-Through Taxes

a) Utilities

Cash working capital is the amount of funds required to finance the day-to-day operations of a utility. The cash working capital requirement is included as part of each of the Utilities' rate base for ratemaking purposes. PGL Ex. JH-1.0 at 19; NS Ex. JH-1.0 at 15-16. To determine the cash working capital requirement, a lead-lag study analyzes the differences between the revenue lags and the expense leads of a utility. Three broad categories of leads and lags are considered: 1) lag times associated with the collection of revenues owed to the utility; 2) lead times associated with the payment of what are commonly called "pass-through" taxes and "energy assistance charges," and 3) lead times associated with the payments for goods and services received by the utility. PGL Ex. JH-1.0 at 20. The Utilities performed a lead-lag study closely conforming to the methodology adopted by the Commission in the Utilities' last rate cases, *In re North Shore Gas Co., et al.*, Dockets 07-0241/07-0242 (Order Feb. 4, 2008) ("*Peoples 2007*"). PGL Ex. JH-1.0 at 20. The only contested aspect of the Utilities' lead-lag cash working capital study relates to pass-through taxes.

The Utilities maintain that the pass-through taxes and energy assistance charges are not recorded as revenue or expense on the income statement, but their collection and payment cause a timing difference in the cash flow that needs to be accounted for. PGL Ex. JH-1.0 at 23-24; NS Ex. JH-1.0 at 20. The Utilities explain that they bill customers for the pass-through taxes in its normal billing process, and the rate payers do not pay the bills immediately to the Utilities when they receive their bills. The payment by the rate payers (or collections by the Utilities) occurs over several months after bills are issued. According to the Utilities, this "lag" in collection is the basis for the Utilities' calculation and use of lag days in its lead lag study. There is a corresponding expense (payment) lead because the Utilities do not remit the taxes to the taxing authorities on the same day they issue the bills to the customers. The due dates of the taxes are based on statutory due dates or various agreements with the taxing authorities. This payment "lead" is the basis for the Utilities' calculation of or use of lead days in its lead-lag study. The Utilities conducted an analysis as approved by the Commission in their last rate cases.

The Utilities refuted Staff's argument, describing the types of pass-through taxes and energy assistance charges and noting that the majority of the pass-through taxes and energy assistance charges were taxes or charges imposed by law on the Utilities and not the customers and were either collected through a separate charge prescribed by law or described within the statute as a charge for utility service. NS-PGL Ex. JH-2.0 at 12.

The Utilities note that the pass-through taxes are not recorded as revenue or expense but they do create timing issues in the collection and payment of the taxes. NS-PGL Ex. JH-2.0 at 13; NS-PGL Ex. JH-3.0 at 8.

According to the Utilities, it is not necessary that the Utilities have the same method ordered for Northern Illinois Gas Company ("Nicor Gas"), because the facts are different. Nicor Gas reportedly collects pass-through taxes, holds them for a time, and then remits the money to various municipalities. NS-PGL Ex. JH-3.0 at 8-9. The Utilities observe that Nicor Gas bases its payments on actual cash collections from customers, which is different from the Utilities. Peoples Gas states that it entered into an agreement with the City of Chicago, dated December 21, 2005, under which it pays, at a specific time, an <u>estimate</u> of the pass-through taxes owed to the City. Prior to this agreement, Peoples Gas states that it paid its taxes based on actual cash receipts from customers. NS-PGL Ex. JH-3.9. North Shore and Peoples Gas submit that they use this same process for all pass-through taxes, whether covered by the City agreement or not. NS-PGL Ex. 2.0 at 14. According to the Utilities, there is a significant difference in methodology; Nicor Gas uses actual cash receipts so it knows it has collected the taxes and holds the money for a period of time before payment, whereas the Utilities make payments based on estimates and whether actually collected or not so the Utilities are uncertain if they have actually received the taxes before or after they have been paid.

Staff, however, proposes to change the methodology, causing a large and unsubstantiated disallowance of a portion of the Utilities' cash working capital. Staff's proposal to arbitrarily assign a revenue lag of zero days to pass-through taxes and energy assistance charges is improper and is not supported by the evidence in these cases.

Staff witness Ostrander first argued in his direct testimony that because cash received from customers for pass-through taxes is not a payment for utility service, there should be no revenue lag. Staff Ex. 3.0 at 7. That incorrect assertion was refuted by Utilities witness Hengtgen in his rebuttal, where he described the types of pass-through taxes and energy assistance charges and that the majority of the pass-through taxes and energy assistance charges were taxes or charges imposed by law on the Utilities and not the customers and were either collected through a separate charge prescribed by law or described within the statute as a charge for utility service. NS-PGL Ex. JH-2.0 at 12.

In his rebuttal testimony, Mr. Ostrander argued that pass-through taxes are not technically "revenues" so they cannot have a revenue lag. Staff Ex. 17.0 at 6. He ignores the fact that the pass-through taxes are not recorded as expense either. Consistent thinking would require that since they are not recorded as expense, they cannot have an expense lead either, but they do create timing issues in the collection and payment of the taxes. This is because the Utilities bill customers for the pass-through taxes in their normal billing process, and the customers do not pay the bills immediately to the Utilities when they receive their bills. The payment by the customers (or collections by the Utilities) occurs over several months after bills are issued. This "lag" in collection is the basis for the Utilities' calculation and use of lag days in its lead lag study. There is a corresponding expense (payment) lead because the Utilities do not remit the taxes to the taxing authorities on the same day they issue the bills to the customers. The due dates of the taxes are based on statutory due dates or various agreements with the taxing authorities. This payment "lead" is the basis for the utilities calculation of or use of lead days in its lead lag study.

Because of the Utilities' method of remitting pass-through taxes based on estimates and not knowing if the taxes have actually been collected, the Utilities calculations of pass-through taxes show an overall cash working capital close to zero, reflecting the lags and leads nearly cancelling each other out. Mr. Hengtgen's lead-lag study shows that for the tax payments to the City of Chicago of $171 million, the net cash working capital amount is a negative $40,000. NS-PGL Ex. JH-3.0 at 10 – 11.

Mr. Ostrander's use of the methodology ordered by the Commission in the Nicor Gas case is not appropriate here. His proposal uses a large expense lead, $23,661,000 for the City of Chicago alone, and zero revenue lag. NS-PGL Ex. JH-3.7P. Mr. Ostrander's conclusion would suggest a massively negative cash working capital figure. Tr. at 749 – 750. However, as he admitted, this is saying that, in effect, the Utilities are holding customers' money for 50.3 days (Peoples Gas) and 74.82 days (North Shore). Tr. at 750 – 752. There is no support in the record for this conclusion or result. While that might have been appropriate in Nicor Gas' situation, it does not reflect the Utilities' facts here.

Mr. Hengtgen's lead-lag study shows that for the tax payments to the City of Chicago of $171 million, the net cash working capital amount is only a negative $40,000. NS-PGL Ex. JH-3.0 at 10-11. This rebuts Staff's argument that investors somehow receive a benefit of the Utilities having pass-through taxes as cash on hand.

Further, contrary to Staff assertions, there are no inconsistencies in the record with regard to pass-through taxes. Staff refers to responses to Staff data requests JMO-14.04 through JMO-14.09, which clearly indicate that payments are based on estimates and the payments are made regardless of whether or not the Utilities collect from the customers. Staff Ex. 17.0 at 7-8 and Attachments C through N (the responses). Those responses also indicate that the source of those payments is the collection of the customers' bills. This is the basis for Utilities' calculation and use of lag days in its lead lag study. Staff's argument for use of zero lag days ignores these facts.

Staff concedes that the Utilities' procedures for collecting and paying pass-through taxes have not changed since the Utilities' most recent rate cases, in which the Commission approved the lead-lag methodology the Utilities continue to use here. Ostrander, Tr. 752 – 753. There is no need for the change Staff proposes. For all the reasons stated herein, the Commission should reject Staff's proposal to change the cash working capital methodology for pass-through taxes.

b) Staff

As explained by Staff witness Ostrander, "Cash Working Capital ("CWC") is the amount of funds required from investors to finance the day-to-day operations of the Companies. A company's CWC requirement may be positive or negative, depending on whether it receives cash from ratepayers for delivery of utility service, on average, slower or faster than it pays expenses. One way to determine the level of CWC to be included in rate base is a lead-lag study that analyzes test year cash transactions and invoices. "In general, lag times are associated with the collection of revenues for delivery of utility service owed to the Companies (that is, the collection of cash from ratepayers for the provision of service lags behind the Companies' cash outlays for the provision of service), and lead times are associated generally with the payments for goods and services received by the Companies (for example, vendors allow the Companies to pay later for goods and services provided currently)." Staff Ex. 3.0 at 3-4. With respect to pass-through taxes, because Investors receive the benefit of the Companies having pass-through taxes as cash on hand to finance the day-to-day operations until the cash is remitted to the appropriate taxing authority they must be accounted for in the cash working capital calculation. *Id*. at 7-8. Therefore, the Commission should adopt revenue lag days of zero for pass-through taxes and reject the Companies' argument that revenue lag days of 40.84 for North Shore and 50.22 for Peoples Gas be included in the CWC revenue requirement.

Staff proposes to reduce the amount of CWC added to rate base for pass-through taxes because pass-through taxes represent funds provided by ratepayers rather than investors. Staff proposes to do this by applying revenue lag days of zero to pass-through taxes in the CWC calculation because 1) in the context of a rate case, pass-through taxes are not operating revenue, and therefore cannot have a revenue lag; and 2) ratepayers provide pass-through taxes for the Company to hold and later remit to taxing bodies. Through the CWC requirement, investors rightly receive a return on their financing of operating expenses which produce operating revenue, if there is a lag in operating revenue covering operating expenses. However, with respect to pass-through taxes, investors have not invested funds to finance operations. If a revenue lag for pass-through taxes is included in the CWC requirement and added to rate base, investors will earn a return on ratepayer supplied funds. Staff Ex. 3.0 at 3-8; Staff Ex. 17.0 at 4-10. The Commission should not allow the Company to increase its rate base for revenue lag on funds for pass-through taxes because funds for pass-through taxes are provided by ratepayers.

Staff and the Companies agree that pass-through taxes are not recorded as revenue or expense on the income statement but the collection and payment of these amounts causes a timing difference in the Companies' cash flow. Staff Ex. 3.0 at 6. The Companies, through the surrebuttal testimony of witness Hengtgen, argue that the use of revenue lag days would reflect the proper timing difference between receipt of pass through taxes and payment to taxing authorities, *i.e.*, pass-through taxes are paid to taxing authorities approximately as cash is received from its customers. NS-PGL Ex. JH-3.0 at 9. However, Staff maintains that the evidence indicates that the Companies do have access to the funds provided from the pass through taxes until the funds are remitted to the taxing authorities.

The Companies acknowledge that the Commission accepted the use of a lag of zero days in the most recent Nicor Gas rate case, *Nicor 2008*. However, the Companies say that their process for paying pass-through taxes is different than the process used by Nicor in *Nicor 2008*. The Companies describe Nicor's process for pass through taxes as amounts are billed, received and held for a period of time, and then remitted at a later date to taxing authorities. The Companies pass-through payment process is based on an agreement with the City of Chicago, which allows the Companies to pay the Municipal Utility Tax and the Chicago Use Tax on the basis of estimated cash receipts. The Companies describe their process for pass through taxes as amounts that are billed and paid to taxing authorities approximately as received. NS-PGL Ex. JH-3.0 at 9-10.

The Companies' assertion that pass through taxes are paid to taxing authorities approximately when received from ratepayers is contradicted by the facts in evidence. In response to Staff Data Requests JMO 14.04 through JMO 14.09 (Staff Ex. 17.0 at 7-8), the Companies describe the process and timing of collection and payment of the various pass-through taxes as follows:

1. The taxes are included in the customer's monthly bill.
2. The Companies collect the taxes.
3. Taxes are paid on or before the due dates.
4. The payments are based on estimated amounts.
5. The payments are made regardless of whether or not the Companies collect from the customers.

Mr. Hengtgen's testimony under cross examination and Staff Cross Hengtgen Ex. 21 (WPG-8, page 45 of 48) provide further support for Staff's position that the Companies do in fact utilize a process for collection and payment of pass through taxes similar to Nicor in that amounts are billed, collected, and held for a period of time, and then remitted at a later date to taxing authorities. Mr. Hengtgen described how the pass through tax liability to the City of Chicago for August 2009 is based on the estimated gross receipts net of a provision of uncollectible accounts that are deemed collected during August 2009 and subsequently paid by one check on September 30th. Tr. at 667-672. The Companies are liable to remit the proper amount due on a timely basis whether the payment of pass-through taxes is based on actual cash receipts or estimates or any other methodology. *Nicor 2008* at 12. The source of funds for such tax payments is ultimately the collection of the ratepayers' bills as confirmed by Mr. Hengtgen. Tr. at 668-669.

The Companies' use of lead days for pass through taxes confirms that pass through taxes deemed collected from ratepayers (during August 2009) are held until remitted to a taxing authority at a later due date (September 30th). The length of time that the Companies have pass-through taxes available for their use has been calculated in the Companies' lead/lag study. *See* Staff Cross Hengtgen Ex. 21. The Commission should not allow the Company to increase its rate base for revenue lag on funds for pass-through taxes because the Companies do indeed receive pass-through taxes from ratepayers, hold those funds, and later remit those funds to the taxing authorities.

c) Commission Analysis and Conclusion

This is a factual question that rests on when a utility must make certain payments, such as taxes, and when it receives the cash from ratepayers to the make the payments. Whether the payments are based on estimate or actual cash receipts does not matter. If shareholders make a payment because the money has not yet been received from ratepayers, then this amount is appropriately contained in the calculation of cash working capital. Lead lag studies are the method by which this is determined. It is to be expected that each utility's lead-lag study will show different results and, thus, the decision in *Nicor 2008* is not controlling.

The Utilities have appropriately used a methodology that matches what the Commission approved in the Utilities' last rate cases. The evidence shows that the Utilities addressed the actual lags and leads for pass-through taxes in their study. Staff's proposal, however, would in effect find that the Utilities are holding customers' money for 50.3 days (Peoples Gas) and 74.82 days (North Shore). Tr. at 750. The evidence does not support this. It appears that Staff's approach improperly ignores the time between when customers are billed for pass through taxes and when the pass through taxes are remitted to the Utilities.

Accordingly, the Utilities' cash working capital methodology for pass-through taxes is accepted.

2. All Other (Uncontested)

All other cash working capital components are uncontested. The figures shown on the Utilities' Revised Schedule B-8's in NS-PGL Exs. JH-3.6N and JH-3.6P are therefore approved.

F. Accumulated Deferred Income Taxes (Uncontested Except for Derivative Adjustments from Contested Adjustments)

1. The Record

The Utilities have shown, on their original Schedule B-9s, the projected balances of Accumulated Deferred Income Taxes at December 31, 2009 and December 31, 2010, and the average amount for the test year. PGL Ex. JH-1.0 at 15-16; NS Ex. JH-1.0 at 12. The Utilities updated and revised those figures in rebuttal and ultimately in surrebuttal. NS-PGL Ex. JH-3.1N and JH-3.1P. Other than derivative adjustments from contested adjustments, the Utilities' surrebuttal figures are not disputed by any party.

2. Commission Analysis and Conclusion

The Commission finds the figures in the Utilities' surrebuttal reasonable and appropriate subject to the derivative adjustments stemming from contested issues as discussed elsewhere in this Order.

G. Reserve for Injuries and Damages

This issue is addressed below.

H. OPEB Liabilities and Adjustment to Remove Pension Asset

1. Utilities

Staff and AG/CUB propose that Peoples Gas' pension asset be excluded from rate base on the theory that it was established by ratepayer-supplied funds. Additionally, despite arguing that the pension asset should be excluded from rate base, Staff argues that North Shore's pension liability should be included in rate base, although AG/CUB agrees with the Utilities that if the Peoples Gas pension asset is excluded then so should the North Shore pension liability. Staff and AG/CUB join in arguing that the Utilities' OPEB liabilities should be included in rate base. The Utilities assert that the Commission should reject such inconsistent treatment. Because the pension asset, the pension liability, and the OPEB liabilities are all related in nature, they should be treated consistently.

The Utilities explain that a utility's accrued pension liability generally results from pension expense calculated based on Financial Accounting Standard ("FAS") 87 being greater than pension contributions. NS-PGL Ex. AF-1.0 at 20-21. A pension asset, however, is created in two ways: (1) contributions to the pension fund; and (2) negative pension expense. Pension plan contributions are based on management decisions with various legal considerations contained in the Employee Retirement Income Security Act of 1972 ("ERISA") and the Internal Revenue Code ("IRC"). NS-PGL Ex. AF-1.0 at 6. The constraints regarding pension funding include: required minimum and maximum contribution levels deductible for income tax purposes and the utility's responsibility to protect the interests of the plan participants and beneficiaries. *Id.* However, pension expense, which is based on FAS 87, represents the annual pension cost that is actuarially determined in a manner that charges each period with the net cost of such benefits attributable during that annual period. *Id.* at 6. The funding rules set forth under ERISA and the IRC are different than the methodology used to determine pension expense under FAS 87. *Id.* With the adoption of FAS 87, the trigger between pension expensing and pension funding was eliminated. *Id.* at 19.

Mr. Felsenthal testified, prior to FAS 87, customers were charged for pension expense in accordance with the requirements of Accounting Principles Board Opinion No. 8, which generally resulted in expensing based on funding. The actuaries would establish funding levels to provide for an accumulation of plan assets to meet the projected plan benefits – no more, no less. Therefore, prior to the adoption of FAS 87, amounts expensed were remitted to the plan to pay for plan benefits. NS-PGL Ex. AF-1.0 at 19. With the adoption of FAS 87, there was no longer a direct link between expensing and funding. Under FAS 87, a distinct calculation is required each year to determine pension expense under Generally Accepted Accounting Principles which takes into consideration a number of factors including service cost, expected returns, interest on projected obligations, etc. A prepaid pension asset results when there is negative pension expense or when contributions are made into the pension fund – in both cases, investor-supplied funding. NS-PGL Ex. AF-1.0 at 19-20.

Further, Utilities witness Felsenthal testified that the other way to create a pension asset is for the annual pension cost computed under FAS 87 to be a negative expense – meaning that the expected return on plan assets exceeds other components of pension cost. *Id.* at 9. An additional reason for negative expense, particularly relevant to Peoples Gas, is the result of pension plan participants accepting lump-sum distributions in lieu of a stream of pension plan benefits, thereby eliminating pension plan obligations and triggering the recognition of a portion of unrealized gains. *Id.* at 9.

Further, Staff attempts to characterize Peoples Gas' pension asset as merely a result of a timing difference. However, Staff fails to recognize that rate base is computed with many items that are timing differences, such as deferred taxes. NS-PGL Ex. AF-2.0 at 3. Even the OPEB liability that Staff and AG/CUB/City propose to deduct from rate base is a timing difference. The fact that a timing difference is involved is irrelevant. *Id.* at 3. Further, under Staff's reasoning, the Commission would have erred in its *ComEd 2005 Rehearing Order* because a debt return was allowed on a pension asset. *Id.* at 3.

According to the Utilities, the evidence demonstrates that for the eight year period, beginning with 1996 (the year after Peoples Gas' second to last rate case, Docket 95-0032, through and including 2003), there was aggregate negative pension expense (credits) each year totaling $174.3 million. NS-PGL Ex. AF-2.0 at 5. Staff's witness noted that, for the subsequent six year period, 2004 to 2009, there is aggregate pension expense of $18.4 million. Staff Ex. 16.0 at 9. However, she did not address the negative pension expense in the prior eight years, and it certainly does not change the numbers for the prior eight years. Further, the Utilities argue that the prepaid pension asset is the cumulative difference between what has been contributed to the pension plan by Peoples Gas, using investor-supplied funds, and what has been expensed under FAS 87. NS-PGL Ex. AF-1.0 at 10. Because the ratemaking process is based on expense, the prepaid pension asset also represents amounts that have been contributed by Peoples Gas to the pension fund that have not been recovered, or that have been treated as a negative pension expense. *Id.* at 10.

Additionally, the argument that there is no evidence that the pension asset was created by contributions made by Peoples Gas, the Utilities believe, is without merit. Utilities witness Felsenthal explained that Peoples Gas' pension asset is a combination of direct contributions (similar to ComEd in Docket 05-0597) or through negative pension expense. NS-PGL Ex. AF 1.0 at 27. The Utilities note that Staff continues to limit its Peoples Gas comparison of total cash contributions and pension expense recorded for the last five years, which results in a net pension expense of a positive $18,394,032. Staff Ex. 16.0 at 8-9. However, Staff continues to conveniently ignore that for the eight years before that (1996-2003), there was a total negative pension expense of $174.3 million. There is no evidence, according to the Utilities, that customers funded the pension asset.

Customers benefit in two ways in the years that there was negative pension expense: (1) reduced operating expenses; and (2) the need for additional rate cases is reduced. NS-PGL Ex. AF-1.0 at 14-15. Negative pension expense, the Utilities contend, benefits investors only to the extent it reduces cash funding requirements – there is no immediate cash benefit. *Id.* at 14.

However, because Peoples Gas has not been allowed by the Commission to include its pension asset in rate base, investors are not allowed to earn a return on their investment. *Id.* at 20. That serves as an incentive, according to the Utilities, for Peoples Gas to make only the minimum required pension plan contribution, which results in greater risk to employees as to the availability of sufficient pension plan funds to pay ultimate plan benefits. *Id.* at 20. It is also contrary to Illinois law, which requires the Commission to establish rates that give the utility the opportunity to earn its authorized return. *E.g., Illinois Bell Tel. Co. v. Illinois Commerce Comm'n,* 414 Ill. 275, 286 (1953); *Citizens Utilities Co. of Ill. v. Illinois Commerce Comm'n,* 153 Ill. App. 3d 28, 30 (3d Dist. 1987).

The Utilities' position is that the Commission should encourage adequate pension plan funding, not send signals to do less. In its Order in Docket 05-0597, a Commonwealth Edison Company ("ComEd") rate proceeding, with respect to a $803 million contribution made by ComEd's parent company to ComEd's pension plan, the Commission acknowledged that "the contribution assisted in providing adequate funding for the retirement obligations of ComEd's workforce and … ComEd's customers saved $30.2 million as a result of the contribution." *In re Commonwealth Edison Co.*, Docket 05-0597 (Order on Rehearing Dec. 20, 2006) at 28.

Recently, the Illinois Appellate Court for the Second Judicial District issued an opinion that affirmed the Commission's decision in ComEd's 2005 rate case (Docket 05-0597) that excludes ComEd pension asset from rate base but allows ComEd to recover at ComEd's cost of long-term debt an $803 million contribution to the pension plan that was made using funds supplied by ComEd's ultimate parent company. *ComEd Appeal* at 17. The Appellate Court reasoned that ComEd had failed to carry its burden of proving that recovery of the $803 million contribution at ComEd's full cost of capital was reasonable or that there was not a less expensive alternative to funding the contribution than that full cost of capital. *Id*. at 16-17. Therefore, the question on appeal did not revolve around whether the funds used to contribute to the pension plan were investor-supplied, but around whether financing the contribution at the utility's full cost of capital, rather than its cost of long-term debt, was proven to be reasonable.

Mr. Felsenthal testified that the only significant difference between the facts in the 2005 ComEd rate case and the instant proceedings is that the source of the pension asset is not as direct. NS-PGL Ex. AF-1.0 at 27. He stated that

> [T]the source of Peoples Gas' pension asset is a combination of debt and equity investors – either through direct contributions (similar to Commonwealth Edison Company) or through negative pension expense, a non-cash credit reducing cash flows producing a requirement to obtain investor funds to "pay" for other cash expenses. But, in either case, the source of the prepaid pension asset is the investor, not the ratepayer, requiring a return on such investment.

Id. at 27.

The Utilities note that Staff cites the 2008, 2004, and 1995 Northern Illinois Gas Company ("Nicor") rate cases where the Commission approved rate bases that reflected deductions for OPEB liabilities but did not incorporate pension assets. However, in those cases, the Commission found as a matter of fact that the pension assets were created by ratepayer-supplied funds. The Order in the 1995 case indicates that the pension balance had gone from negative to positive since the utility's 1987 rate case without any pension plan contributions. *In re Northern Illinois Gas Co.*, Docket 95-0219, 1996 Ill. PUC Lexis 204 at 20 (Order April 3, 1996) ("*Nicor 1996*"). The Commission's Order in *Nicor 1996* distinguished the Commission's approval of inclusion of a pension asset in rate base in *In re Central Illinois Light Co.*, Docket 94-0040, 1994 Ill. PUC Lexis 577 (Order Dec. 12, 1994) ("*CILCO 94-0040*"), on the grounds that there the utility, unlike Nicor, had made pension plan contributions and the inclusion was not a contested issue. *Nicor 1996* at 22. The Commission expressly noted in the 2004 case that Nicor acknowledged that it had made no pension plan contributions since the 1995 case. *In re Northern Illinois Gas Co.,* Docket 04-0779, at 22 (Order Sept. 20, 2005) ("*Nicor 2004*"). In the Order for the 2008 case, the Commission merely affirms that "the *facts* have not changed" from the previous two rate cases (emphasis added). *Nicor 2008* at 18. Thus, the Utilities argue, *Nicor 1996, Nicor 2004,* and *Nicor 2008* Orders do not support Staff's and AG/CUB/City's proposed adjustments, because the relevant facts as relied upon by the Commission are not the same, and the *CILCO 94-0040* case supports inclusion.

The argument that Peoples Gas' pension asset is merely a result of accounting rules, namely Financial Accounting Standards ("FAS") 158 must be rejected as well. Contrary to Staff's arguments, the prepaid pension asset upon which Peoples Gas is seeking a return is exactly the level of the pension asset that would exist on a FAS 87 basis (without implementation of FAS 158), which is $152.5 million. NS-PGL Ex. AF-2.0 at 5-6. FAS 158 required that (1) the funded status, which is a liability of $70.9 million, to be put on the books as a liability; and (2) the unrecognized actuarial losses and prior service costs recorded as a regulatory asset. *Id.* at 6. Under FAS 87, these three items were each of a component of the prepaid asset. Thus, the Utilities argue that the net amount of Peoples Gas' pension asset is unaffected by FAS 158. *Id.* at 6.

Staff's position also is inconsistent in that Staff proposes to include the North Shore pension liability in rate base. Staff's position is incorrect, and is inconsistent with Staff's testimony in the Utilities' 2007 rate cases. NS-PGL Ex. AF-1.0 at 2, 3, 20-21. Even AG/CUB/City and their witness Effron propose symmetrical treatment of the Peoples Gas pension asset and the North Shore pension liability.

With respect to the Utilities' OPEB liabilities, Staff, the AG, and CUB/City all cite previous Commission Orders, such as *Nicor 2005*, to support their adjustments to subtract the OPEB liabilities from rate base. The past Orders each refer to *Nicor 1996*, which differentiates between the two elements of retiree benefits by stating that "NI-GAS continues to control the ratepayer-supplied OPEB funds" implying that control is a distinguishing factor not requiring symmetrical treatment. *Nicor 1996*, 1996 Ill. PUC Lexis 204 at *23. However, the Utilities argue that control is not an appropriate standard for determining whether an asset or liability should or should not be considered in rate base as there are other elements of rate base that are not within a utility's "control". For example, Accumulated Deferred Income Taxes ("ADIT") are not controlled by the Utilities, yet such amounts are generally considered in the rate base calculation. NS-PGL Ex. AF-1.0 at 22. The determinant as to whether an item should or should not be considered in the rate base calculation is the source of the funds. *Id.*

The Utilities assert that, for the same reasons that it is appropriate to include the pension asset in Peoples Gas' rate base, North Shore's pension liability should be included in its rate base. The Utilities maintain that, because Peoples Gas' pension asset, North Shore's pension liability, and the Utilities' OPEB liabilities each represent a commitment to pay retirees, either a pension or a promised health and welfare benefit, there is no reason to treat them differently. NS-PGL Ex. AF-1.0 at 23. The accrued pension asset and pension liability, along with the OPEB liabilities, should be included in rate base. However, alternatively, if the Commission concludes that the Peoples Gas pension asset should not be included in its rate base, then North Shore's pension liability should be excluded, and the Utilities' respective OPEB liabilities should be excluded. The Utilities note that AG/CUB/City witness Effron agrees that there should be consistent treatment of Peoples Gas' pension asset and North Shore's pension liability and he does not consider either one in his calculation of the Utilities' rate bases. AG/CUB/City Ex. 1.0 at 12.

2. AG

The "Retirement Benefits, Net" consists of two components: prepaid pensions (Peoples Gas) or the accrued liability for pension costs (North Shore) and the accrued liability for future post-retirement benefits other than pension. AG/CUB/City Ex. 1.0 at 10. The AG explains that the prepaid pension is mainly the effect of pension income recorded by PGL pursuant to Statement of Financial Accounting Standards 87. *Id*. When the returns generated by the pension investments have been greater than the other elements of the periodic pension costs, pension income (or negative pension expense) is recorded on the books of account. However, no cash is actually withdrawn from the pension funds. Rather, the offset to this non-cash income is a charge to prepaid pensions. *Id.* at 10-11.

The second component is primarily the accrued liability for future post-retirement benefits other than pensions ("OPEB"), mainly health care costs. *Id*. at 11. Pursuant to Statement of Financial Accounting Standards 106, the Companies must accrue for the payment of future post-retirement benefits other than pensions. To the extent that the accruals are greater than the actual cash disbursements, accrued liabilities will be reflected on the Companies' balance sheets. *Id*.

PGL offsets the accrued liability for OPEB against prepaid pensions in the calculation of the "Retirement Benefits, Net" that it includes in rate base. NS adds the accrued liabilities for pensions and OPEB together and subtracts that amount from its rate base. *Id*. In the last rate case, the Companies did not take account of the accrued pension and OPEB balances in the determination of rate base. *Id*. In response to testimony by Staff and intervenors proposing to deduct the accrued OPEB liabilities from rate base, the Companies stated that if the accrued OPEB liabilities are deducted from rate base, then the prepaid or accrued pension balances should also be recognized. In its Order in Dockets 07-0241/07-0242, the Commission found that the accrued OPEB liability should be deducted from rate base but that the pension balances should not be recognized in the determination of rate base. Final Order, Dockets 07-0241/07-0242 at 36.

Consistent with the Commission's findings in Peoples 2007, Mr. Effron eliminated the pension balances from rate base, but treated the accrued liability for postretirement benefits other than pensions as rate base deductions. He also eliminated the accumulated deferred income taxes related to the prepaid or accrued pensions. The net effect of this adjustment is to reduce PGL "Retirement Benefits, Net" by $143,240,000 (AG Ex. 1.2, Sched. B) and related accumulated deferred income taxes $57,438,000 (AG Ex. 1.2, Sched. B-3), for a net reduction to the PGL rate base of $85,802,000.

With regard to North Shore, the effect of Mr. Effron's proposed adjustment is to reduce the rate base deduction for "Retirement Benefits, Net" by $3,022,000 (AG Ex. 1.1, Sched. B) and to increase the related accumulated deferred income taxes by $228,000 (AG Ex. 1.1, Sched. B-3), for a net increase to the NS rate base of $3,250,000.

In his rebuttal testimony, NS-PGL witness Felsenthal stated that it was his understanding that in Docket 05-0597 (ComEd's Proposed Increase in Rates), the Commission's Order on Rehearing allowed an $803 million pension contribution in rate base. NS/PGL Ex. AF-1.0 at 26. However, Mr. Felsenthal's understanding is not accurate. As pointed out by Mr. Effron, who was a witness in that case, the $803 million pension contribution was not actually included in rate base. AG/CUB/City Ex. 2.0 at 5. Rather, the Commission allowed a debt return on the pension contribution in pro forma operation and maintenance expenses. He opined that it is important to note that it was established in that case that the $803 million pension contribution was specifically financed by the issuance of long-term debt. *Id*.

In addition, the Commission distinguished between the $803 million pension contribution specifically financed by the issuance of debt and other prepaid pension assets in that case. The debt return on the $803 million pension contribution was included in the revenue requirement. However, the other prepaid pension assets were excluded from rate base and there was no recognition of any return requirement on the other prepaid pension assets in the revenue requirement in that order. This treatment was continued in Docket 07-0566, ComEd's next rate case.

The AG notes that Utilities argue that the pension asset, the pension liability and the OPEB liabilities are all related in nature, and should be treated consistently. The Company opines that the Commission's decision to not allow the Company to include its pension asset in rate base prevents investors from earning a return on their investment and creates an incentive for Peoples to "make only the minimum required pension plan contribution, which results in greater risk to employees' pension benefits. Citing the Second District Appellate Court's decision in the appeal of the 2005 ComEd rate case, in which the Court upheld the Commission's decision to exclude ComEd's pension asset from rate base but allow ComEd to recover at ComEd's cost of long-term debt an

$803 million contribution to the pension plan, the Companies try to argue that the Appellate Court's decision supports the inclusion of the PGL/NS pension asset in rate base.

In response, the AG states that Mr. Effron pointed out in his direct and rebuttal testimonies, the debt return on the $803 million pension contribution was included in the revenue requirement in the ComEd case. However, the other prepaid pension assets were excluded from rate base and there was no recognition of any return requirement on the other prepaid pension assets in the revenue requirement in Docket No. 05-0597. AG/CUB/City Ex. 2.0 at 5. Rather, the Commission allowed a debt return on the pension contribution in pro forma operation and maintenance expenses. He opined that it is important to note that it was established in that case that the $803 million pension contribution was specifically financed by the issuance of long-term debt. *Id*.

In addition, Mr. Effron explained that the Commission distinguished between the $803 million pension contribution specifically financed by the issuance of debt and other prepaid pension assets in that case. The debt return on the $803 million pension contribution was included in the revenue requirement. However, the other prepaid pension assets were excluded from rate base and there was no recognition of any return requirement on the other prepaid pension assets in the revenue requirement in that order.

In the instant case, Mr. Effron updated his adjustment to the Retirement Benefits – Net based on the rebuttal testimony of Ms. Phillips and Mr. Hengtgen in his own rebuttal testimony. *Id*. at 6. His calculation of rate base in Mr. Effron's rebuttal testimony reflects the updates addressed in the rebuttal testimony of Ms. Phillips and Mr. Hengtgen, and the AG argues that it should be incorporated in the revenue requirement for the Companies adopted by the Commission.

3. Staff

The Companies included in their respective rate bases a total amount identified as "Retirement Benefits, Net". For Peoples Gas, the retirement benefits combine the pension asset with the Other Post Employment Benefits ("OPEB") liability to derive the net amount of total retirement benefits the Company has added to its rate base. For North Shore, the retirement benefits combine the pension liability with the OPEB liability to derive the total liability for retirement benefits by which North Shore has reduced its rate base.

Staff witness Pearce proposed an adjustment of $155,496,000 (before accumulated deferred income taxes) to remove Peoples Gas' pension asset from rate base because it was created with funds supplied by ratepayers, not shareholders. Accordingly, Staff's position is that shareholders should not be allowed to earn a return on an asset that was created with normal operating revenues collected from utility ratepayers.

The Commission has addressed ratemaking treatment of pension assets and OPEB liabilities in many dockets. In their last rate case, he Commission found that neither the pension asset nor contributions to the pension plan should be reflected in the utilities' rate base. The Commission also found that the treatment of the pension asset should not determine the treatment of the OPEB liability. Accordingly, the Commission supported Staff and Intervenor adjustments to reflect OPEB liabilities as a rate base reduction. *Peoples 2007* at 36.

The Commission has addressed the pension asset issue in several cases involving other Illinois utilities, as well. For example, in Docket 08-0363, the Commission rejected Nicor's request to include its pension asset in rate base. The Commission has consistently rejected Nicor's request to include its pension asset in rate base in prior cases as well, including Dockets 04-0779 and 95-0219. The Commission found, in both cases, that the pension asset was created by ratepayer-supplied funds, not by shareholder-supplied funds, and concluded that ratepayers should not be denied the benefits associated with the previous overpayment for pension expense which they funded. Accordingly, the Commission concluded that the pension asset should be eliminated from rate base.

Also, in the ComEd Rehearing Order in Docket 05-0597, the Commission allowed ComEd to earn a debt return on the amount of the contribution, to be recovered through operating expense, after the Company demonstrated that the contribution was directly financed through long-term debt issuance. The fact pattern of Docket 05-0597 is unique to ComEd and the facts and circumstances of Docket 05-0597 do not resemble the facts of the instant proceeding in any way. However, it is significant to note that the Commission's order in Docket 05-0597 was recently upheld on appeal. By upholding the Commission's decision on appeal, the Court did not disturb the Commission's decision to not allow a single part of ComEd's pension asset or contribution into utility rate base, which is exactly what the Companies want the Commission to do in this case. Accordingly, Staff argues that no part of a pension asset should be allowed into the Companies rate base.

The Commission has also addressed the treatment of OPEB liability in the previously discussed Nicor rate proceeding, Docket 04-0779 and in the Ameren Companies' request for an increase in delivery service tariffs ("DST"), Docket Nos. 06-0070, 06-0071, and 06-0072, (Consol.) (AmerenCILCO, AmerenCIPS, AmerenIP) Order dated November 21, 2006 at page 27. In these cases, the Commission found that the OPEB liability should be treated as a reduction of utility rate base.

For ratemaking purposes, a rate base reduction of the accrued liability associated with OPEB is appropriate to the extent that the test year obligation is unfunded or partially funded. The accrued liability represents the aggregate OPEB costs recognized in the income statement which has not been paid to a third party. Ratepayers have supplied funds for future obligations; therefore, a source of cost free capital has been provided to the utility which should be recognized in the revenue requirement as a reduction from rate base.

At issue in the instant proceeding is the treatment of the Peoples Gas pension asset and the North Shore pension liability. Essentially, Mr. Felsenthal believes the pension asset was created with shareholder funds and therefore, represents an asset on which shareholders should earn a return. In contrast, Staff contends the pension asset was created with contributions using monies supplied by ratepayers through the collection of utility rates. Although the determination of a net pension asset or liability at any given point in time will be impacted by multiple factors, including returns on invested assets and actuarial assumptions, ratepayers ultimately, through the collection of utility rates, have borne and will continue to bear the cost of the pension plans. Since the pension asset was funded by normal operations, rather than provided by shareholders, shareholders should not earn a return on it. The pension expense is and has been reflected in utility rates. The pension expense is determined by accounting rules based on actuarial calculations that recognize an amount of pension cost for that period. Contributions to the pension plan represent payments of that obligation with monies provided through the collection of utility revenues from ratepayers. Staff Ex. 16.0.

Utilities witness Felsenthal asserted that "[a]s with any capital expenditure, the source of the contribution is investors, as ratepayers pay for the cost of service consisting of annual operating costs and return (rate base times rate of return)." NS-PGL Ex. AF-1.0, lines 232 – 234. Staff disagrees with this characterization. The net pension asset is not the result of a "capital expenditure" by shareholders. Instead, it is the net difference between the fair value of the pension fund and the projected pension obligation, as measured at a specific point in time. The pension fund value is based on the investments included in the pension fund and the pension obligation is based on estimates, determined by actuarial analysis using various assumptions and methods. Accordingly, the net pension asset is a function of comparing two components—the value of the pension fund and the projected pension obligation. If either the value of the pension fund or the amount of the pension obligation changes, the net difference (for Peoples Gas, a net pension asset) will also change. This difference is basically a timing difference that results from several factors, including differences between the amount of pension expense reflected in rates and the amount of cash contributed to the plan, actuarial assumptions, market performance that impacts the underlying investments, and factors that impact the obligation, like curtailments. Staff Ex. 16.0 at 5 – 6.

Utilities witness Felsenthal agrees that pension expense for ratemaking and financial reporting purposes (which is reflected in the test year revenue requirement) will usually differ from funding requirements (i.e., cash contributed to the pension plan) since the two amounts are determined according to different sets of rules. Accordingly, the Utilities and Staff agree that timing differences impact the resulting net pension asset. However, the Utilities' witness further asserted that:

> To the extent that cumulative contributions to the pension plan exceed the cumulative accounting costs based on FAS 87, there is a balance sheet entry equal to the excess. This is the prepaid pension asset, representing the employer's contributions which have not yet been reflected as pension cost in the accounting records or on the financial statements. NS-PGL Ex. AF-1.0, lines 133 – 137.

While that statement is not necessarily untrue, it provides a simple but incomplete analysis because it fails to address the main factor that has contributed to the net pension asset in the instant Peoples Gas proceeding; specifically, a regulatory asset created by the application of accounting rules. Moreover, there is no evidence in the instant proceeding to support the contention that cumulative cash contributions in excess of the pension expense alone, account for the Peoples Gas' pension asset. Staff Ex. 16.0, lines 134 – 152.

Utilities witness Felsenthal described at length the origin of Peoples' Gas pension asset, as the difference between the fair value of assets set aside to pay for projected benefit obligations and the projected benefit obligation. He further explained there are two typical transactions that result in a pension asset, one being that the entity makes pension contributions in excess of pension cost, and the other resulting when annual pension cost according to FAS 87 is a negative, not a positive expense. NS-PGL Ex. AF-1.0, lines 168 – 178. However, Mr. Felsenthal did not specifically indicate which of these two transactions created the Peoples' Gas pension asset in the instant proceeding.

Based on this rationale, the reader might infer that as of December 31, 2010, cumulative pension contributions from Peoples Gas will exceed cumulative pension expense reflected in utility rates by $155,496,000 (NS-PGL Ex. JH-2.0, Ex. JH-2.7P, line 15, column (I)), the amount of net pension asset Peoples Gas seeks to reflect in the test year rate base. This is simply not credible. As stated previously, there is no evidence in the record of this proceeding to support the contention that Peoples Gas' shareholders have made contributions to the pension plan in an amount $155,496,000 greater than the amounts collected from ratepayers through utility rates (or in any other amount). Moreover, based on the Company's response to Staff Data Request BAP-12.03, during the most recent five-year period from 2004 to the present, including the Company's projection for the balance of 2009, total cash contributions by Peoples Gas to the pension plan total $37,743,228 and pension expense recorded by Peoples Gas totals $56,137,260. Staff Ex. 16.0, Attachment A. This evidence demonstrates that just within the last five years, pension expense, which is recovered in rates, has exceeded pension contributions by $18,394,032. Staff Ex. 16.0, lines 189 – 225.

In the aforementioned quote, Mr. Felsenthal refers to the prepaid pension asset and the related regulatory asset. Referring to the rebuttal testimony of Mr. Hengtgen, NS-PGL Ex. JH-2.7 P, reflects the Company's updated pension and Other Post Employment Benefits ("OPEB") liability amounts. NS-PGL Ex. JH-2.0, lines 352 – 356. As this exhibit shows, the net pension asset consists of the Net Pension Funded Status, a liability of $70,859,000 (NS-PGL Ex. JH-2.7 P, line 9, column (I)) and the Net Pension Regulatory Asset of $226,355,000 (NS-PGL Ex. JH-2.7 P, line 14, column (I)), which sum to the Total Pension net asset of $155,496,000 (NS-PGL Ex. JH-2.7 P, line 15, column (I)) that Peoples Gas seeks to reflect in rate base. As is clear from the descriptions used by the Company, the funded portion of the pension is a liability. Accordingly, the net pension asset that the Company seeks to recover in rate base is largely a function of accounting rules according to FAS 158, not a result of excess contributions. It is also worth noting that the description "regulatory asset" is used to denote timing differences that will eventually be collected from ratepayers. If ratepayers were not eventually going to bear this cost, it could not by definition be classified as a regulatory asset. Staff Ex. 16.0, lines 234 – 253.

FAS 87 refers to Statement of Financial Accounting Standards No. 87 entitled *Employers' Accounting for Pensions* and FAS 158 refers to Statement of Financial

Accounting Standards No. 158 entitled *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans.* Basically, FAS 87 covers the employers' accounting for pension plans. FAS 158 amends FAS 87 with regard to financial statement disclosure and generally requires companies to reflect the funded status of the pension plan on the balance sheet instead of disclosing the funded status in footnotes attached to the financial statements, as previously allowed. (The funded status of the pension plan basically is the difference between the fair value of pension plan assets and the projected benefit obligation.) FAS 158 (issued in September 2006) affects employers' balance sheets by requiring the entity to recognize the overfunded or underfunded status of the pension plan as an asset or liability and to recognize changes in the funded status as other comprehensive income. FAS 158 does not alter the way annual pension cost is calculated. Staff Ex. 16.0, lines 256 – 271.

The Companies obtained an actuarial update and revised the 2010 test year pension expense and related regulatory asset in the rebuttal phase of this proceeding. Based on the rebuttal testimony of Utilities witness Phillips, the actuarial update increased the Peoples Gas 2010 test year pension expense by $6,268,000. NS-PGL Ex. CMP-1.0, lines 104 – 106. The impact on the forecasted average balances for the 2010 test year rate base is as follows:

> For the 2010 test year, the initial filing reflected an average prepaid pension of $16,416,000 with a related regulatory asset of $124,715,000; reflecting a net pension asset of $141,131,000. The updated forecasted average balances for the 2010 test year are an accrued pension liability of $70,859,000 with a related regulatory asset of $223,373,000; reflecting a net pension asset of $152,514,000, a net increase of $11,383,000. NS-PGL Ex. CMP-1.0, lines 144 – 149.

The impact of the actuarial update on the test year filing proves two things: (1) since pension expense increased, ratepayers are the ones who bear the cost of the pension plan and provide the revenues that fund the Company's contributions; and (2) the $98,658,000 increase in the pension regulatory asset, ($223,373,000 – $124,715,000) is the result of a timing difference created through application of the accounting rules, not excess cash contributions from shareholders. Staff Ex. 16.0, lines 273 – 296.

Because ratepayers bear the cost of the pension plans in utility rates, it is improper to reflect pension contributions or pension assets in rate base. Such treatment would allow shareholders to earn a return on ratepayer-supplied funds. Similarly, it is proper to reduce rate base by the amount of pension liability. The North Shore pension liability represents the amount of expense that has been recovered in rates and not yet contributed to the pension plan by the Company. Therefore, it represents a cost-free source of capital to the Company and must be a reduction of rate base.

4. Commission Analysis and Conclusion

In the Utilities' last rate case, Dockets 07-0241/07-0242, the Commission found that the accrued OPEB liability should be deducted from rate base, but that the pension balances should not be recognized in the determination of rate base. Staff and the

Utilities suggest changes to different aspects of the Commission's prior decision. The AG is the only party that advocates that the same approach be used in this docket. The Commission finds that neither the Utilities nor Staff provided a compelling reason to reach different conclusions here.

Staff and the Utilities both argue that the Commission's decision in Docket 05-0597, which was recently upheld on appeal, supports their proposed outcome for the Peoples Gas pension asset. The Commission's treatment of ComEd's $803 million pension contribution, however, was based on different facts than those presented here. Unlike the situation in Docket 05-0597, the Utilities have not shown that Peoples Gas' pension asset was created with shareholder funds. Without that evidence, there is no reason to believe that the pension asset is funded by any other source than ratepayers. The Commission's decision to allow ComEd shareholders to earn a debt return on a specific pension contribution, but to exclude the rest of ComEd's pension asset from rate base, was upheld on appeal. We agree with Staff that the ComEd decision supports the exclusion of pension assets from rate base.

The Utilities have given us no reason to overturn our decision from their last rate case. Although the Utilities state that the pension asset was created with shareholder funds, no evidentiary support was provided. The Commission finds no support in the record to allow for the inclusion of Peoples Gas' pension asset in rate base which in turn would allow shareholders to earn a return on ratepayer supplied funds.

The question then becomes whether Staff or the AG has treated North Shore's pension liability appropriately. Staff's entire argument and testimony, upon which the Commission is meant to overturn its prior decision, is that the "North Shore pension liability represents the amount of expense that has been recovered in rates and not yet contributed to the pension plan by the Company. Therefore, it represents a cost-free source of capital to the Company and must be a reduction of rate base." Staff Initial Brief at 37 and Staff Ex. 16.0 at 14. This is not a sufficient basis for adopting a different methodology here.

Consistent with our decision in the Utilities' last rate case, the Commission finds that it is appropriate to treat Peoples Gas' pension asset and North Shore's pension liability consistently, i.e., the AG has appropriately excluded both from the rate base calculation. Staff has not provided sufficient evidence or argument for a different conclusion here.

We note that the Commission has also addressed the treatment of OPEB liability in the Nicor rate proceeding, Docket 04-0779, and in the Ameren Companies' request for an increase in delivery service tariffs, Dockets 06-0070/06-0071/06-0072 (Consol.) Order dated November 21, 2006 at page 27, as well as the Utilities' last rate case. In these cases, the Commission found that the OPEB liability should be treated as a reduction of utility rate base. In the Utilities' last rate case, the Utilities argued that pension asset/liability and OPEB liability should be treated consistently because both involve employee benefits. No further argument is offered in this proceeding for different treatment of the OPEB liability and, thus, the OPEB liability treatment remains unchanged.

No party gives us reason to overturn our decision in the prior rate case. The pension asset/liability should be removed from the rate base equation, as proposed by the AG, and the OPEB liability shall be reflected as a reduction to rate base.

I. Approved Rate Base

Based on the rate base as originally proposed by the Utilities along with the conclusions above, the utility rate bases for Peoples Gas and North Shore may be summarized as follows:

Approved Rate Bases (in thousands)

	Peoples Gas	North Shore Gas
Gross Utility Plant	$ 2,572,460	$ 400,021
Accumulated Provision for Depreciation and Amortization	(1,068,165)	(165,670)
Net Plant	$ 1,504,295	$ 234,351
Additions to Rate Base:		
Materials and Supplies	10,064	2,441
Cash Working Capital	34,002	819
Gas in Storage	52,723	7,873
Budget Plan Balances	12,605	834
Retirement Benefits, Net	(87,669)	-
Deductions From Rate Base:		
Accumulated Deferred Income Taxes	(284,103)	(48,046)
Pre-1971 Investment Tax Credits	-	-
Reserve for Injuries and Damages	(8,307)	(1,044)
Customer Advances for Construction	(392)	(511)
Customer Deposits	(32,088)	(2,895)
Retirement Benefits, Net	-	(10,746)
Rate Base	$ 1,201,130	$ 183,075

V. Operating Expenses

A. Overview

1. North Shore

North Shore proposes operating expenses and operating income figures of $67,004,000 and $16,301,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part and certain updates.

2. Peoples Gas

Peoples Gas proposes operating expenses of $455,540,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part and certain updates.

B. Uncontested Issues

1. Natural Gas Prices for Purposes of Company Use Gas, Uncollectibles Expense, and North Shore Franchise Gas

a) The Record

The Utilities, Staff, AG, and CUB agree that the natural gas prices for the purposes of company use gas, uncollectibles expense, and North Shore's franchise gas should be updated based upon data in the Utilities' August 2009 Gas Charge filings. NS-PGL Ex. CMG-3.0 at 2-3; 5, 6; NS-PGL SM-Ex. 3.0 Rev. at 7-8; AG/CUB Ex. 4.0 at 9-10, 11, 12; Staff Ex. 27.0 at 17-19, 19-20; Tr. at 914-915.

b) Commission Analysis and Conclusion

For purposes of company use gas, uncollectibles expense, and North Shore franchise gas, the Commission finds that the use of the gas prices based on data in the Utilities' August 2009 Gas Charge filings to be reasonable.

2. Union Wages

a) The Record

Staff witness Hathhorn proposed to reduce operating expenses of North Shore and Peoples Gas by $69,000 and $582,000 (before income taxes), respectively, to correct an error in calculating test year union wages at the non-union rate. Staff Ex. 1.0 at 29, Sched. 1.2 P, p. 1, Sched. 1.4 P, p. 1, Sched. 1.2 N, p. 1, corr., and Sched. 1.4 N, p. 1. AG/CUB/City and the Utilities agreed. AG/CUB/City Ex. 1.0 at 17; NS-PGL Ex. SM 2.0 at 4, 5; NS-PGL Ex. JH-2.0 at 4. No witness opposed those adjustments.

b) Commission Analysis and Conclusion

The Commission finds that the adjustments to reduce operating expenses of North Shore and Peoples Gas by $69,000 and $531,000 (gross amounts), respectively, are appropriate. Therefore, each of these amounts is approved.

3. Company Use Gas

a) The Record

AG/CUB's proposal to include North Shore's cost of company use gas for 2010 test year, which was inadvertently omitted from North Shore's direct testimony figures and Part 285 filing, is uncontested. AG/CUB/City Ex. 1.0 at 23; NS-PGL CMG-2.0, Sched. 2.6N.

b) Commission Analysis and Conclusion

The Commission finds that the inclusion in operating expenses of North Shore's cost of company use gas for 2010 test year is appropriate and uncontested. Thus, this amount is approved. See above for the discussion of the update of the gas price.

4. IBS Charges

a) The Record

AG/CUB's proposal to reduce the operating and maintenance expenses of North Shore and Peoples Gas by $360,000 and $7,493,000 (gross amounts), respectively, for test year 2010 for Integrys Business Support, LLC ("IBS") charges based on the Utilities' responses to Staff data request DLH 4.06 is uncontested. AG/CUB/City Ex. 1.0 at 16 17; NS-PGL Ex. SM-2.0 at 5.

b) Commission Analysis and Conclusion

The Commission finds that the adjustments to reduce the operating and maintenance expenses of North Shore and Peoples Gas by $360,000 and $7,493,000 (gross amounts), respectively, for the test year is appropriate and uncontested. Thus, these reductions are approved.

5. Distribution - Gasoline and Fuel

a) The Record

Staff witness Seagle originally proposed to decrease the Utilities' transportation fuel costs for the test year. Staff Ex. 13.0 at 13-17. The Utilities corrected and updated Staff's calculations. NS-PGL Ex. CMG-2.0 at 7. Mr. Seagle agreed with the revised adjustments. Staff Ex. 27.0 at 3. No witness disagreed.

b) Commission Analysis and Conclusion

The Commission agrees with the Utilities and Staff that the test year fuel prices, as originally proposed, are higher than current prices. Therefore, the Commission approves the Utilities' correction and updates of these costs. The Utilities' revised adjustments are approved.

6. Customer Accounts - Uncollectible Expense Except for AG/CUB Sales Revenues Adjustment – Related

a) The Record

There is no contested issue regarding uncollectibles expenses, except for the derivative impact on uncollectibles expenses resulting from AG/CUB's proposed adjustment to the Utilities' sales revenues, discussed below.

b) Commission Analysis and Conclusion

The Commission finds that uncollectibles expense is uncontested, except for the derivative impact resulting from AG/CUB's proposed adjustment to the Utilities' sales revenues, discussed in Section V(C)(5) of this Order.

7. Administrative & General Expenses

a) Account 921

(1) The Record

Staff proposed adjustments to limit the amount of test year Office Supplies and Expenses. Staff Ex. 3.0 at 8. The Utilities revised Staff's adjustments. NS-PGL Ex. CMG-2.0 at 4-5. Staff accepted the revisions. Staff Ex. 17.0 at 3. No witness opposed the revised adjustments.

(2) Commission Analysis and Conclusion

Staff's adjustment, as revised by the Utilities, to limit the amount of test year Office Supplies and Expenses is appropriate and uncontested. Therefore, these revised adjustments are approved.

b) Interest on Budget Payment Plans

(1) The Record

Staff's proposal to decrease operating and maintenance expenses of North Shore and Peoples Gas by $118,000 and $618,000, respectively, is uncontested. Staff Ex. 3.0 at 13-14; NS-PGL Ex. SM-2.0 at 5.

(2) Commission Analysis and Conclusion

The Commission finds Staff's adjustment to decrease operating and maintenance expenses of North Shore and Peoples Gas by $118,000 and $618,000, respectively, for test year interest expense on budget payment plan balances to be appropriate and uncontested. Thus, the adjustments are approved.

c) Interest on Customer Deposits

(1) The Record

Staff witness Ostrander's proposal to decrease operating and maintenance expenses of North Shore and Peoples Gas by $85,000 and $950,000, respectively, is uncontested. Staff Ex. 3.0 at 14-16; NS-PGL Ex. SM-2.0 at 5.

(2) Commission Analysis and Conclusion

The Commission finds Staff's adjustments to decrease operating and maintenance expenses of North Shore and Peoples Gas by $85,000 and $950,000, respectively, for test year interest expense on customer deposits to be appropriate and uncontested. Thus, these adjustments are approved.

d) Lobbying

(1) The Record

Staff's proposal to reduce operating and maintenance expenses of North Shore and Peoples Gas by $2,000 and $12,000, respectively, in order to disallow lobbying costs included in the dues paid by the Utilities is uncontested. Staff Ex. 6.0 at 3-4; NS PGL Ex. SM-2.0 at 5.

(2) Commission Analysis and Conclusion

The Commission finds Staff's adjustment to reduce operating and maintenance expenses of North Shore and Peoples Gas by $2,000 and $12,000, respectively, in order to disallow certain lobbying costs to be appropriate and uncontested. Therefore, such reductions are approved.

e) Social and Service Club Dues

(1) The Record

Staff's proposal to reduce operating and maintenance expenses of North Shore and Peoples Gas by $8,000 and $52,000, respectively, for certain service club membership dues is uncontested. Staff Ex. 6.0 at 4; NS-PGL Ex. SM-2.0 at 5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's adjustments to reduce operating and maintenance expenses of North Shore and Peoples Gas by $8,000 and $52,000, respectively, for certain service club membership dues to be appropriate and uncontested. Accordingly, such reductions are approved.

f) Civic, Political, and Related Activities

(1) The Record

Staff's proposal to reduce the operating expenses of North Shore and Peoples Gas by $2,000 and $6,000, respectively, for lobbying related taxes other than income, and their operating and maintenance expenses by $10,000 and $23,000 (gross amounts), respectively, for expenses associated with lobbying and related activities is uncontested. Staff Ex. 6.0 at 6-7; NS-PGL SM-Ex. 2.0 at 5; NS-PGL Ex. JH-2.0 at 4.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's adjustments to reduce the operating expenses of North Shore and Peoples Gas by $2,000 and $6,000, respectively, for lobbying related taxes other than income, and their operating and maintenance expenses for North Shore and Peoples Gas by $10,000 and $23,000 (gross amounts), respectively, for expenses inherent with lobbying and related activities that were included in the Civic, Political and Related Activities account to be appropriate and uncontested. Thus, these adjustments are approved.

g) Non-union Base Wages Adjustment in DLH – 4.06 (PGL)

(1) The Record

Staff proposed an adjustment to reduce the operating expenses of Peoples Gas by $86,000 for non-union merit increases relating to the Utilities' response to Staff data request DLH 4.06. Staff Ex. 1.0, Schedule 1.8P, footnote (e). The Utilities agreed. NS PGL Ex. SM-2.0 at 4. No witness opposed this adjustment.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's adjustment to reduce the operating expenses of Peoples Gas by $86,000 for non-union merit increases to be appropriate and uncontested. Therefore, such adjustment is approved.

h) Liberty Audit Outside Contractor Fees (Peoples Gas)

(1) The Record

Staff and AG/CUB proposed an adjustment to reduce Peoples Gas' operating and maintenance expense by $540,000 to remove the fees of certain consultants related to the Liberty Audit follow up work. Staff Ex. 1.0 at 32-33 and Sched. 1.13 P, line 1; AG/CUB/City Ex. 1.0 at 25. The Utilities agreed. NS-PGL Ex. SM-2.0 at 4, 5. No witness opposed this adjustment.

(2) Commission Analysis and Conclusion

The Commission finds that the adjustment to reduce Peoples Gas' operating and maintenance expense by $540,000 to remove the fees of Liberty Consulting Group and Huron Consulting Group related to the Liberty Audit follow up work to be appropriate and thus, is approved.

The remaining portion of Staff's adjustment related to the Liberty Audit is addressed below.

i) Rate Case Expenses

(1) The Record

Staff recommends that the Commission find the amounts expended by the Utilities for rate case expense in this proceeding to be just and reasonable and consistent with Section 9-229 of the PUA. Staff Ex. 17.0 at 14 15. The Utilities agreed. NS-PGL Ex. SM-3.0 Rev. at 4.

AG/CUB witness Effron initially proposed an adjustment to reduce Peoples Gas' rate case expenses on the theory that there was a double counting of certain costs. AG/CUB/City Ex. 1.0 at 25-26. Utilities witness Moy showed that there was no double counting. NS-PGL Ex. SM-2.0 at 8. Mr. Effron then agreed that his adjustment was not necessary. AG/CUB Ex. 4.0 at 11-12.

(2) Commission Analysis and Conclusion

The Commission finds that the amounts expended by the Utilities ($4,788,000 for Peoples Gas and $2,598,000 for North Shore) for rate case expense in this proceeding are just and reasonable and consistent with Section 9-229 of the PUA. Thus, these amounts are approved. Further, the Commission finds that the withdrawal of the AG/CUB adjustment to reduce Peoples Gas' rate case expense to be uncontested and correct. Therefore, we approve the withdrawal.

j) Franchise Requirements Expenses (North Shore)

(1) The Record

AG/CUB proposed an adjustment to reduce North Shore's franchise requirement expenses. AG/CUB/City Ex. 1.0 at 26. Ms. Gregor updated the adjustment as discussed above. NS-PGL Ex. CMG 2.0 at 8. Mr. Effron agreed with the updated adjustment. AG-CUB Ex. 4.0 at 12.

(2) Commission Analysis and Conclusion

The Commission finds that North Shore's test year franchise requirement expenses should be updated as agreed. Thus, North Shore's revised adjustment is approved.

k) Regulatory Asset – Welfare

(1) The Record

Staff and AG/CUB proposed adjustments to the amortization of regulatory assets for welfare costs, which the Utilities accepted. NS-PGL Ex. SM-3.0 Rev. at 1, 2, 4. No witness opposed those adjustments as corrected and updated.

(2) Commission Analysis and Conclusion

The Commission finds the Utilities' revised adjustments for the amortization of regulatory assets for welfare costs to be appropriate and uncontested. Therefore, these amounts are approved.

l) Regulatory Asset – Pension

(1) The Record

Utilities witness Moy proposed corrected adjustments relating to the amortization of regulatory assets for pension costs. NS-PGL Ex. SM-3.0 Rev. at 6-7. The adjustments are uncontested.

(2) Commission Analysis and Conclusion

The Commission finds the Utilities' adjustments for the amortization of regulatory assets for pension costs to be appropriate and uncontested. Therefore, these amounts are approved.

m) Employee Benefits Update

(1) The Record

The Utilities provided updated 2010 test year numbers for the Utilities' respective pension and benefits expenses figures in their operating expenses. NS-PGL Ex. CMP 1.0. No witness opposed those updates.

(2) Commission Analysis and Conclusion

The Commission finds that the updated 2010 test year numbers for the Utilities' respective pension and benefits expenses figures in their operating expenses to be appropriate and uncontested. Thus, these amounts are approved.

n) Merger Costs and Savings

(1) The Record

Staff proposed adjustments to reconcile the most recent actual and projected Costs to Achieve with the total recovery of merger costs since the effective date of the tariffs approved in Peoples Gas' and North Shore's last rate cases. Staff Ex. 2.0 at 7. In rebuttal, Staff revised the adjustments. Staff Ex. 16.0 at 16-18. In Surrebuttal Testimony, Ms. Moy agreed with Staff's calculations to reconcile total merger costs expected to recover with actual costs incurred but using July 31, 2009 forecast data in NS-PGL Exs. SM 3.8N and SM-3.8P. Staff agreed with the revised adjustments in NS-PGL Cross Pearce Ex. 25. No contested issue remains.

(2) Commission Analysis and Conclusion

The Commission finds Staff's revised adjustments to merger costs as presented in NS-PGL Cross Pearce Ex. 25 to be appropriate and uncontested. Therefore, these amounts are approved.

8. Depreciation

a) Inventory Reclassification

(1) The Record

Staff witness Hathhorn's proposal to reduce the operating expenses of North Shore and Peoples Gas by $2,000 and $18,000, respectively, in order to reflect the impact of inventory reclassifications is uncontested. Staff Ex. 1.0 at 30, Scheds. 1.11 N and 1.11 P; NS-PGL Ex. SM-2.0 at 4.

(2) Commission Analysis and Conclusion

The Commission finds that the reduction of the Utilities' operating expenses to reflect the impact of the inventory reclassifications to be appropriate and uncontested.

Thus, the adjustments are approved. See also the discussion above regarding the accumulated reserve for depreciation and amortization.

b) IBS Mainframe

(1) The Record

AG/CUB's proposal to amortize the remaining book value of the IBS mainframe server as of the beginning of 2010 over three years is uncontested. AG/CUB/City Ex. 1.0 at 24-25; NS-PGL Ex. SM 2.0 at 5.

(2) Commission Analysis and Conclusion

The Commission finds the amortization of the remaining book value of the IBS mainframe server beginning in 2010 over three years to be appropriate and uncontested. Therefore, it is approved.

9. Taxes Other Than Income Taxes - Real Estate Taxes

a) The Record

Staff's proposal to decrease the expense for real estate taxes of North Shore and Peoples Gas by $45,000 and $207,000, respectively, to reflect actual 2008 real estate taxes is uncontested. Staff Ex. 5.0 at 4-6; NS-PGL Ex. SM 2.0 at 5.

b) Commission Analysis and Conclusion

The Commission finds Staff's adjustment to decrease the Utilities' expense for real estate taxes to be appropriate and uncontested. Therefore, the adjustment is approved.

10. Revenues - Accounting Charge Revenues

a) The Record

The Utilities propose that the natural gas prices for the purposes of the accounting charge revenues be updated based upon the data in the Utilities' August 2009 Gas Charge Filings, as with the other items adjusted based on natural gas prices. NS-PGL Ex. 3.0 Rev. at 8. This is uncontested.

b) Commission Analysis and Conclusion

The Commission finds that the Utilities' proposal to update the accounting charge revenue for natural gas prices data in their August 2009 Gas Charge Filings to be appropriate and uncontested; thus, it is approved.

11. GRCF

a) The Record

The Utilities' Gross Revenue Conversion Factors (the amounts by which the rate increases must be increased for income taxes and uncollectibles to allow recovery of the costs of service) are uncontested. NS Ex. SM 1.1 at Sched. A-2; PGL Ex. SM 1.1 at

Sched. A-2. Staff's Initial Brief contained a very slight discrepancy in terms of rounding of the factor for North Shore to fewer digits, but the factors remain uncontested.

b) Commission Analysis and Conclusions

The Commission finds the Utilities' Gross Revenue Conversion Factors to be appropriate and uncontested, and thus, they are approved.

C. Contested Issues

1. Incentive Compensation

a) Utilities

The Utilities assert that no witness challenged the testimony of Utilities witness Hoover, the Director of Compensation of the Utilities' ultimate parent company, with over 25 years of experience in human resources, regarding the prudence and reasonableness of each of the incentive compensation plans at issue. Mr. Hoover's testimony established, among other things, that: (1) the Utilities design their total cash compensation packages (base pay plus target incentive pay) at market median based on other energy service companies based on data from Towers Perrin, a nationally recognized compensation and benefits firm; (2) the Utilities design their total compensation programs, including their incentive compensation programs, in order to attract and retain a sufficient, qualified, and motivated work force; and (3) attracting and retaining such a work force benefits customers by making sure there are enough employees to perform needed work, by maintaining and improving the quality of work, and reducing the expenses associated with recruiting and retaining new employees. NS-PGL Ex. JCH-2.0.

Even in today's economic environment, the Utilities' approach is prudent and reasonable, and the alternative of moving more compensation to base pay would put them at a disadvantage in the labor market. NS-PGL Ex. JCH-2.0 at 7.

Mr. Hoover testified, among other things, that:

- The "financial" metrics of the plans are net income metrics, which have both a cost side and a revenue side. Even though the Commission has not approved net income metrics in prior cases, it has approved cost control metrics. So, he asserted, the costs tied to net income metrics should be allowed.
- The operational measures "behind" the financial measures in the non-executive plan have direct benefits to customers, such as reducing system leaks.
- The targets are set each year to motivate employee behavior and are considered achievable stretch goals designed to motivate employee achievement from a competitive level to an outstanding level.
- The metrics involving achievements by affiliates benefit Illinois customers, because it encourages the sharing of best practices.

NS-PGL Ex. JCH-1.0 at 3-8; NS-PGL Ex. JCH-2.0 at 2-4.

Mr. Hoover also testified, as to the stock plans, that they are an important part of the overall total compensation package, are designed to help attract and retain a qualified and motivated work force, and that without them the Utilities' compensation packages would be less competitive because their labor market competitors, both energy and non-energy companies, offer compensation packages that include base pay, incentive pay, and stock plans. NS-PGL Ex. JCH-1.0 at 9; NS-PGL Ex. JCH-2.0 at 4.

The Utilities urge the Commission to consider the evidence regarding the prudence and reasonableness of the incentive compensation costs or the benefits received by customers. The Commission must apply Illinois law governing uncontradicted evidence. "Where the testimony of a witness is neither contradicted, either by positive testimony or by circumstances, nor inherently improbable, and the witness has not been impeached, that testimony cannot be disregarded by the trier of fact." *Bazydlo v. Volant*, 164 Ill. 2d 207, 215 (1995).

The principle that a utility should recover its prudent and reasonable costs of service is well-established. It is settled law, moreover, that employee salaries are operating expenses and, as such, are recoverable in full so long as they are prudent and reasonable. *See, e.g., Villages of Milford v. Illinois Commerce Comm'n*, 20 Ill. 2d 556, 565 (1960) ("*Milford*").

In their 2007 rate cases, the Commission approved the Utilities' incentive compensation costs associated with two of their five plans. *Peoples 2007* at 66-67. The allowed costs were (1) the costs associated with the 45% of the non-officers "TIA" plan metrics that were "operational" and (2) all of the costs associated with the individual performance bonus plan. *Id*. The disallowance of the other costs is pending on appeal by the Utilities.

Previously, in the 2005 ComEd rate case (Docket 05-0597), the Commission allowed the utility to recover half of its incentive compensation costs. *In re Commonwealth Edison Co.*, Docket 05-0597 (Order July 26, 2006) ("*ComEd 2005*") at 95-97. ComEd appealed. The Illinois Appellate Court for the Second Judicial District recently affirmed. *ComEd 2005 Appeal* at 9-14.

The Second District noted established law on a utility's recovery of its prudent and reasonable costs, adding that the costs must pertain to the utility's tariffed services, citing *DuPage Util. Co. v. Illinois Commerce Comm'n*, 47 Ill. 2d 550, 560 (1971) ("*DuPage*"), which distinguished *Milford. ComEd 2005 Appeal* at 10-11. In *DuPage,* the Court, in affirming the disallowance of half of the salaries of three company officers of a utility with 840 customers, distinguished *Milford*, but in *DuPage* the Commission found and the evidence supported that the salaries were excessive rather than reasonable, including evidence that the officers only worked part-time and maintained only a minimal contact with the utility's day to day operations, and that their salaries were disproportionately high compared to comparable utilities. *DuPage*, 47 Ill. 2d at 560. There is no claim, much less any evidence, of excessive compensation on those or any other grounds in the instant cases. The only evidence is to the contrary. The Second District also discussed some of ComEd's evidence of customer benefits, finding that "this evidence certainly does provide support for ComEd's position, it does not compel the conclusion that ComEd seeks." *ComEd 2005 Appeal* at 13. Finally, and critically, the Second District relied on the fact that the Commission had approved half of ComEd's incentive compensation costs. *ComEd 2005 Appeal* at 14.

Here, however, unlike the ComEd case, the numbers set forth above show that Staff proposes to disallow almost 100% of the Utilities' incentive compensation costs, even though they include some "operational" metrics, such as metric tied to system leak reductions. Thus, the "tangential benefit" and "apportionment" reasoning of the Second District does not apply here.

Staff argues that its successive percentage disallowances, which end up disallowing very close to 100% of the Utilities' executive and non-executive incentive compensation program costs, are warranted on four grounds: (1) the plans include "financial" (net income) metrics that fail the Commission's cost recovery standards, (2) the 2010 targeted levels are unlikely to be achieved, (3) the plans incorporate affiliate performance metrics, and (4) the plans have an Integrys net income trigger (gate).

As to Staff's first ground, Staff is right that the Commission in many cases has found that "financial" metrics do not fall within the Commission's standards, and that the Commission in several cases has held or stated that that reasoning applies to net income metrics, but the Utilities urge a different result here. The Utilities note that the Commission is required to establish rates that are just and reasonable to the utility and its shareholders as well as customers. 220 ILCS 5/9-201(c); *Business and Professional People for the Pub. Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175, 208 (1991) ("*BPI II*"). Even assuming that financial metrics benefit shareholders, that is not a basis for disallowing them. Indeed, Staff's witness acknowledged that the fact that a metric benefits shareholders does not necessarily mean that it does not also benefit customers (Tr. at 714-715), although she did claim in her written testimony, citing past Commission Orders, that net income metrics do not benefit customers.

Second, the financial metrics at issue here, net income metrics, do in fact benefit customers. Net income metrics indisputably have both a cost side and a revenue side, however, by definition. NS-PGL Ex. JH-1.0 at 4. Even though the Commission has not approved net income metrics in prior cases, it has approved cost control metrics and, thus, the costs tied to net income metrics should be allowed. NS-PGL Ex. JH-1.0 at 4. In the alternative, they should be disallowed only by half. AG-CUB witness Effron proposed to disallow only half of the Utilities' incentive compensation costs on the grounds that the metrics are financial (except for his proposal to disallow all costs allocated from affiliates as financial). AG/CUB/City Ex. 1.0 at 20-21.

With respect to Staff's second ground, the "unlikely to achieve" ground, the Utilities note that their payment of substantial incentive compensation costs was recognized in their 2007 rate cases. *See Peoples 2007* at 57-67. Moreover, Staff does not deny that the Utilities paid substantial amounts in 2007 and 2008. Furthermore, the evidence is that the targets are set each year to motivate employee behavior and are considered achievable stretch goals designed to motivate employee achievement from a competitive level to an outstanding level. NS-PGL Ex. JCH-2.0 at 4. Staff's witness appears in effect to be complaining that when employees failed to meet certain target levels in 2007 and 2008 their incentive compensation was reduced (Staff Ex. 1.0 at 10-

11), but that is exactly how the programs are supposed to work. Staff's two factual examples are particularly poor choices as support for Staff's position, moreover, because they involve system leak reductions and occupational safety metrics, two metrics that are operational, not financial, even under the most narrow view of the Commission's standards. Those are exactly the kinds of things that the Commission has made clear that it is desirable to encourage.

Staff's third ground is that the metrics include affiliate performance metrics, but the Utilities' witness pointed out that the Utilities and their affiliates share a team-based philosophy that encourages the sharing of best practices that benefit Illinois customers, and that affiliates share in staff support and thus in the support expense. NS-PGL Ex. JCH-2.0 at 6. According to the Utilities, Staff cites no evidence on this point.

Staff's fourth ground is the plans have an Integrys net income trigger, but the discussion of financial and affiliate-related metrics above applies to that ground.

Staff's remaining disallowances, which are based on reflecting disallowances in the Utilities' 2007 rate cases, are founded on the Order in those cases, which Staff correctly notes is still in place but on appeal. Staff Init. Br. at 65-66.

The AG/CUB/City do not identify any ground for disallowance here. Thus, their proposed disallowances also should not be adopted. However, if the Commission were to order any disallowances here, then they should be no greater than AG-CUB's proposed adjustments, which would disallow roughly half of the Utilities' incentive compensation costs. The Utilities note that, while they respectfully differ from the Second District's reasoning as well as taking the position that it is not applicable here in any event, AG/CUB's proposed adjustments, by disallowing roughly half of the costs, would move this aspect of this Docket closer to the facts on which the Second District relied in its "tangential benefit" and "apportionment" reasoning. The evidence shows that Staff's application here of the Commission's past standards is illogical and unreasonable, and Staff's admissions on cross-examination, also support disallowing no more than half of the costs at issue.

The Utilities assert that the Commission should reject Staff's and AG-CUB's proposed disallowances. The costs at issue are prudent and reasonable, and they benefit customers in multiple respects.

b) AG

In recent cases, the Commission has generally allowed the recovery of incentive compensation only when it is demonstrated that such compensation operates to benefit the utility's customers, rather than operating solely for the benefit of shareholders. See, e.g., Dockets 07-0241/07-0242 (Consol.), Order at 66. In its direct case, Peoples Gas included $5,620,000 of incentive compensation in 2010 test year operation and maintenance expenses, and NS included $1,072,000 of incentive compensation in 2010 test year operation and maintenance expenses. AG/CUB/City Ex. 1.0 at 9. The AG asserts that a portion of this incentive compensation expense is not properly recoverable from ratepayers.

As noted by Mr. Effron, unless the Companies can demonstrate that the goals employees are expected to achieve under the plans at issue would benefit ratepayers, the incentive compensation related to those goals should not be recoverable from ratepayers. The achievement of goals such as quality of service, reliability, public safety, reducing absenteeism, and cost containment are at least arguably in the interest of ratepayers. However incentive compensation based on financial goals such as maximizing profitability and growth, increasing earnings per share, or increasing return on equity is beneficial only to shareholders, and not, the AG maintains, properly recoverable from ratepayers.

Mr. Effron explained, for example, if all else is equal, higher rates will result in higher revenues, which in turn will result in higher earnings and return on equity. *Id*. at 20. Thus, including incentive compensation related to such goals in the revenue requirement would, in effect, require customers to reward utility management on a contingency basis for getting them to pay higher rates. As shareholders are the primary beneficiaries of the attainment of financial goals such as increases to earnings and return on equity, it should be those shareholders, not customers, who bear the cost of the incentive compensation related to the achievement of such financial goals. *Id*.

The incentive compensation included in test year operation and maintenance expense by the Companies includes compensation paid directly to employees of the Companies and compensation allocated from affiliates, including IBS. *Id*. at 20-21. Of the incentive compensation paid directly to employees of the Companies, 50% relates to operational goals, such as customer satisfaction and safety, and 50% relates to net income, which is a shareholder goal. *Id*. at 21. Mr. Effron testified that with regard to the incentive compensation allocated from affiliates, 100% appeared to relate to shareholder-oriented financial goals. *Id*. at 21.

Based on Mr. Effron's review of the Companies' incentive compensation, 50% of the incentive compensation paid directly to employees of the Companies and 100% of the incentive compensation allocated from affiliates should be eliminated from the incentive compensation included in the Companies' revenue requirements. These adjustments result in a $4,567,000 reduction to Peoples Gas test year operation and maintenance expense and a $944,000 reduction to NS test year operation and maintenance expense. AG/CUB/City Ex. 1.1, Sch. C-2 [NS], AG/CUB/City Ex. 1.2, Sch. C-2 [PGL].

Utilities witness Hoover argued that both its Executive and Non-Executive incentive compensation plans are designed to attract and retain highly qualified and motivated employees. NS/PGL Ex. JCH-1.0 at 3, 7. But this reasoning does not demonstrate a sufficient nexus between the expense and customer benefit. The interests of ratepayers and shareholders are not always completely aligned. When incentive compensation seeks to achieve goals that primarily benefit shareholders, then it is not unreasonable to require that shareholders bear the cost of that incentive compensation. AG/CUB/City Ex. 4.0 at 9. This does not imply that the incentive compensation results in excessive or unreasonable salaries. Rather, it is matter of matching the costs and benefits of the programs, so that costs are borne by the beneficiaries. *Id.*

For all of the reasons cited above, the Commission should adopt Mr. Effron's recommended reduction to the forecasted levels of incentive compensation in accordance with the adjustments presented on AG/CUB/City Exs. 1.1, Schedule C-2 (NS) and AG/CUB/City Ex. 1.2, Schedule C-2.

c) Staff

Staff recommends that the Commission accept Staff witness Hathhorn's proposed adjustments to reduce each Company's rate base and operating expenses for incentive compensation expenses. The adjustment is comprised of four subparts, which are:

A) Disallowance of Executive Incentive plan costs related to shareholder-oriented goals, performance goals unlikely to be achieved, Company affiliate-performance goals, and performance goals tied to financial goals;

B) Disallowance of Non-Executive Incentive plan costs related to shareholder-oriented goals, performance goals unlikely to be achieved, Company affiliate-performance goals, and performance goals tied to financial goals;

C) Disallowance of the Companies' stock plan costs related to shareholder-oriented goals; and

D) Disallowance of capitalized incentive compensation previously disallowed by the Commission.

Staff bases its adjustment on its understanding of prior Commission orders. Staff notes that in the Companies' most recent rate case, Dockets 07-0241/07-0242 (Consol.), the Commission concluded that incentive compensation costs are recoverable in rates only if the utility demonstrates tangible benefits to ratepayers.

Staff notes that the Illinois Appellate Court issued a decision on September 17, 2009, in which it upheld this Commission's decision to exclude incentive compensation from ComEd's base rates. *ComEd Appeal*. This decision makes clear that the long line of Commission cases conditioning recovery of incentive compensation costs based upon consideration of whether those costs benefit ratepayers is proper. As noted by the court, "both *Citizens Utility Board* [*v. Illinois Commerce Comm'n, 166 Ill. 2d 111, 121 (1995)*] and the Act expressly make room for considerations beyond simply whether an expenditure is reasonable and prudent." *Id*. at 10. After reviewing relevant case law, the court concluded "there is ample precedent making a benefit to ratepayers a condition upon which the recovery of salary-related expense depends." *Id*. at 12. The court also confirmed that the utility has the burden of demonstrating a sufficient nexus between plan measures and a benefit to ratepayers. *Id*. at 13. Thus, any argument by the Companies that it is legally improper for the Commission to consider benefits to ratepayers with respect to incentive compensation costs is without merit and contrary to Illinois law.

The Companies argue that the testimony of Utilities witness Hoover, Director of Compensation for the Utilities, should be the determining factor regarding the cost recovery of incentive compensation in this case because Mr. Hoover is an expert on human resources ("HR") unlike the witnesses offered by Staff and AG/CUB/City. The Companies' reliance on their witness' expertise is misplaced. The question before the Commission concerns the application of appropriate ratemaking theory and practice to the recovery of the Companies' incentive compensation costs. With respect to this issue, the expertise of the Staff and AG/CUB/City witnesses is much more substantial than that of the Companies' witness. It is the appropriate ratemaking treatment of incentive compensation costs that is in question. No one has called into question whether the Companies' incentive compensation programs are appropriate from a human resources perspective. Tr. at 713. Past Commission orders are unambiguous that the Commission weighs and often agrees with the testimony of non-HR experts in this matter of cost recovery.

The Companies incorrectly conclude that the Court's conclusion that a utility must demonstrate more than tangential benefits to receive rate recovery is inapplicable since the *ComEd 2005 Appeal* considered the fact that ComEd received rate recovery of half of its incentive compensation based on performance-based components, and Staff's adjustment in this case disallows both operational (i.e. performance-based) and financially based goals. The Court in *ComEd 2005 Appeal* had no reason to discuss or analyze the evidence of benefits to ratepayers from ComEd's performance or operational goals since ComEd did not appeal the Commission's decision to allow recovery of performance based incentive compensation and that issue was not before the Court. The analysis and reasoning in *ComEd 2005 Appeal* in no way validates the Companies' apparent interpretation of that decision to guarantee utilities some particular percentage of rate recovery of incentive compensation. *Id.* The Companies have failed in their requirement to demonstrate any reasonable benefit to ratepayers in this case, and in fact have not proposed any apportioned option; rather they present only an all-or-nothing proposal. In short, the Companies chose to criticize the Commission's standard rather than meet it.

Staff supports the proposition that if a goal benefits both shareholders and ratepayers, that shareholders should not bear all the costs. However, Staff's position is critically conditional on the utility demonstrating in evidence some reasonable basis to allocate benefits to ratepayers. The *ComEd 2005 Appeal* makes clear that simply arguing that certain incentive plans attract good employees and raise the level of service is too remote of a benefit to justify rate recovery. *ComEd 2005 Appeal* at 15.

Disallowance of Certain Executive Incentive Plan Costs

Staff recommends disallowances of approximately 88% and 87% respectively of the Executive Incentive plan costs [$722,000 of $816,000 (Peoples Gas) and $140,000 of $161,000 (North Shore)] the Companies propose to recover in the revenue requirement since those costs were not shown to benefit ratepayers. Specifically, and as discussed in more detail below, Staff proposed the following disallowances:

- Shareholder oriented goals – Disallow 70% of the costs of the Executive Incentive Plan because 70% of the payout is based upon the achievement of the specified financial measures of the following entities: 1) Integrys Energy Group, Inc.'s ("IEG") consolidated net income, 2) Peoples Gas' or North Shore's net income, 3) Integrys' combined regulated subsidiaries net income, and 4) Integrys Energy Services' net income; Staff Ex. 15.0, Attachment A.;

- Unlikely achievement of performance – Disallow 20% (Peoples Gas) and 10% (North Shore) of the remaining Executive Incentive plan expense for performance goals unlikely to be achieved;
- Company affiliate-performance goals – Disallow 17% (Peoples Gas) and 24% (North Shore) of the remaining Executive Incentive plan expense as an estimate for the performance goals that are based upon achievements of Peoples Gas' and North Shore's affiliates; and
- Performance goals tied to financial goals – Disallow 50% of the remaining Executive Incentive plan expense performance goals which are tied to IEG's net income.

With respect to shareholder-oriented goals, Staff disallowed 70% of the administrative and general expense costs of the Executive Incentive plan that is based upon the achievement of stated financial measures of the above-stated entities [$571,000 (Peoples Gas) and $113,000 (North Shore)]. The Companies acknowledge that "…the ICC has previously approved measures that are specifically related to cost control or to cost reduction, although it has not approved the net income measure." NS-PGL Ex. JCH-1.0 at 4. However, the Companies contend that to the extent net income is a "hybrid of revenue and cost, the costs associated with the Utilities' Executive Incentive Plan should be allowed even under the logic of the Commission's standards." *Id.* The Companies are correct that the Commission has repeatedly denied cost recovery of incentive compensation costs based upon achievement solely of a net income level - a goal determined to benefit shareholders primarily over ratepayers. Net income is a result of revenues minus costs. The Companies have made no showing that any specific cost reduction goals exist, that any such goals are related to Peoples Gas' or North Shore's operations, or that any such cost reductions are reflected in the test year expense. Rather, the test year net income goals are determined on an Integrys Energy Group consolidated basis and include the results of both regulated and unregulated Peoples Gas and North Shore affiliates. Staff Ex. 15.0 at 13-14.

Further, much of the financial measures in the Executive Incentive plan relate to the operations of Peoples Gas' and North Shore's affiliates rather than those of the utilities. The Companies cannot demonstrate benefits to Illinois ratepayers for goals based upon total enterprise results encompassing regulated operations in Minnesota, Michigan, and Wisconsin, as well as non-regulated operations throughout Integrys Energy Group, Inc.

The Companies oppose Staff's adjustment for the Executive Incentive Plan costs because, according to them, it "fulfills a legitimate purpose, and is not excessive…and, as a result, is prudent." NS-PGL Ex. JCH-1.0 at 3. Staff disagrees with the Companies' criteria for rate recovery of incentive compensation expense. Staff Ex. 15.0 at 11. Staff's adjustment is not based on the amount of the Executive Incentive Plan, but rather on the failure to meet criteria previously found necessary by the Commission. Further, an expense may not be allowable in rates even if it is not, in and of itself, "excessive." Lobbying expenses are an example of this scenario, since they are barred from rate recovery no matter the amount. *Id*., lines 302-307. Even if the levels of incentive compensation included in the revenue requirement were not considered to be excessive, the costs of incentive compensation should not be included in the revenue requirement if the utility fails to demonstrate that the costs are prudent, reasonable and provide tangible benefits to Illinois ratepayers.

With respect to performance goals unlikely to be achieved, historical results demonstrate that the Companies are unlikely to achieve their performance goals. Staff disallows 20% (Peoples Gas) and 10% (North Shore) of the remaining administrative and general expense for the Executive Incentive plan costs for performance goals unlikely to be achieved under the Executive Incentive plan [$49,000 (Peoples Gas) and $5,000 (North Shore)]. For Peoples Gas only, 10% of incentive compensation based upon achievement of performance goals relates to a goal based upon reduction in system leaks. The goal is based on the ratio of outside gas leaks cleared as compared to the number of outside gas leaks received. Staff Ex. 15.0, Attach. A. However, in 2008, the actual reduction in system leaks result for Peoples Gas was below target. Staff 15.0, Attachment D. This historical performance calls into question the accuracy of the test year forecasted amount being based upon achievement of target level measures that have not been achieved in the past. Staff Ex. 1.0 at 10-11. Further, another 10% of each Company's incentive compensation is based upon achievement of performance goals for employee safety goals based on the Occupational Safety and Health Administration ("OSHA") recordable incident rates. However, in 2007 and 2008, the actual performance of both Companies related to its employee safety goals was below target. Staff Ex. 15.0, Attach. D. This historical performance calls into question the accuracy of the test year forecasted amount being based upon achievement of OSHA recordable incident rates that have not been achieved in the past. Staff Ex. 1.0 at 11.

The Companies present a discussion of the Executive Incentive Plan's non-financial measures and conclude that, "in summary, these measures have a direct impact to customers." NS-PGL Ex. JCH-1.0 at 5-6. However, to consider a plan's costs for rate recovery, the plan along with the Company's historical plan achievements must be considered. Staff Ex. 15.0 at 14. The Companies further argue that their performance goals based upon the achievement of Peoples Gas' and North Shore's affiliates represent a "team-based Company philosophy" wherein the Companies share best-practices which benefits Illinois customers. The Companies further state that "all subsidiaries share in staff support and should share in the support expense." NS-PGL Ex. JCH-1.0 at 6. However, following this logic would lead to the unreasonable requirement that the Commission analyze in this record the Companies' affiliates' performance goal results in Minnesota, Michigan, and Wisconsin. The Companies must be able to demonstrate in this proceeding's record the benefits of incentive compensation expense to Illinois ratepayers. The Companies are free to design their plans using a team-based philosophy, but are not exempt from the rate recovery criteria established by the Commission over a number of consistent orders, discussed below. Staff Ex. 15.0 at 15-16.

The Companies discuss their compensation philosophy and conclude that "[a]ttracting and retaining a sufficient, qualified and motivated work force benefits the Utilities' customers by making sure there are enough employees to perform needed work, by maintaining and improving the productivity and quality of work, and by reducing the expenses associated with recruiting and training new employees." NS-PGL Ex. JCH-1.0 at 7-8. However, the test year costs are not directly based upon these goals. As discussed above, the goals that trigger the test year incentive compensation costs are not based upon this statement, but rather the specific goals and measures identified in Staff Ex. 15.0, Attachments A, B, and C.

Staff's adjustments are consistent with the Commission's policy to disallow incentive compensation plan costs when the plans do not provide a ratepayer benefit. In Docket 01-0432, the Commission concluded that Illinois Power Company should not be allowed to recover from ratepayers the expenses associated with its incentive compensation plan because the Company did not demonstrate that the plan provides net benefits to ratepayers. *In re Illinois Power Co.*, Docket 01-0432, Order at 42 (March 28, 2002).

With respect to Company affiliate-performance goals, Staff disallows 17% (Peoples Gas) and 24% (North Shore) of the remaining administrative and general expenses of the Executive Incentive plan costs as an estimate for the performance goals that are based upon achievements of Peoples Gas and North Shore's affiliates [$8,000 (Peoples Gas) and $1,000 (North Shore)]. The disallowances represent the ratio of the Companies' IBS/Corp SSO (shared services) and IBS Gas Services groups' incentive compensation expense for the Executive Incentive plan to the total Executive Incentive plan cost. Staff Ex. 1.0 at 13.

The test year incentive compensation expense for all plans assumes the "target" level of performance is achieved, with the target based on the approved 2008 incentive compensation plans. Staff Ex. 1.0 at 12. The Executive Incentive plan states that "[t]here will be no payouts for financial measure results unless Integrys Energy Group, Inc. Consolidated Net Income threshold outcome level is reached." Staff Ex. 1.0, Attachment A. However, in 2008, the IEG net income actual result was below target. Staff Ex. 1.0, Attachment D. This historical performance calls into question the accuracy of the test year forecasted incentive compensation amount being based upon achievement of target level IEG net income that has not been achieved in the past.

Further, the performance goals included in the Executive Incentive plan also include goals based upon results of Peoples Gas' and North Shore's affiliates. The IBS/Corp SSO (shared services) and IBS Gas Services groups, both of which allocate expenses to the test year, measure achievement of performance goals based on MER, MGU, UPPCO, and WPSC results in addition to Peoples Gas' and North Shore's results. Therefore, these groups could generate incentive compensation expense because performance goals are met in Wisconsin, Minnesota, and Michigan but not necessarily for achievements by Peoples Gas or North Shore. Staff Ex. 1.0 at 13. Staff's adjustments are consistent with the Commission's policy to disallow incentive compensation plan costs when the plans do not provide a tangible benefit to Illinois ratepayers.

With respect to performance goals tied to financial goals, Staff disallows 50% of the of the remaining administrative and general expenses for the Executive Incentive plan costs associated with performance goals that are tied to IEG net income [$94,000 (Peoples Gas) and $21,000 (North Shore)]. In 2009, the plan changed so that if the consolidated net income threshold performance level of IEG is not reached, any earned non-financial measure payouts will be reduced by 50%. Staff Ex. 1.0 at 13-14 and Staff Ex. 15.0, Attach. E. This calls into question the accuracy of the test year forecast that the performance goals will be paid out at the 100% target level since the payouts will be based upon IEG's consolidated net income targets, which have not been achieved in the past. Staff Ex. 15.0, Attach. D.

Disallowance of Certain Non-Executive Incentive Plan Costs

The structure of the Non-Executive Incentive plan mirrors the Executive Incentive plan. Staff Ex. 15.0, Attach. B and C. The only differences are the weighting of the financial goals versus performance or non-financial goals, and the estimated proportionate share of performance goals costs based upon the Companies' affiliates' goals. First, the financial weighting is 50/50 for the Non-Executive Incentive plan, rather than 70/30 for the Executive Incentive plan. Staff Ex. 1.0 at 14-15. Second, the estimated disallowance for Company affiliate goals based upon the ratio of the Companies' IBS/Corp SSO (shared services) and IBS Gas Services groups' incentive compensation expense for the Non-Executive Incentive plan to the total Non-Executive Incentive plan cost are 74% and 59% for Peoples Gas and North Shore, respectively. *See* Schedule 1.7 P and N, page 3, note (f). Therefore, Staff's adjustments for the Non-Executive Incentive plan are based upon the same facts and arguments as for the Executive Incentive plan discussed above. The result of Staff's analysis disallows approximately 98% (Peoples Gas) and 92% (North Shore) of the operating expense and rate base Non-Executive Incentive plan costs [$4,218,000 of $4,280,000 (Peoples Gas expense); $509,000 of $517,000 (Peoples Gas rate base) and $989,000 of $1,071,000 (North Shore expense) and $97,000 of $105,000 (North Shore rate base)] the Companies propose to recover in the revenue requirement but have not shown to benefit ratepayers.

Disallowance of the Companies' stock plan costs related to shareholder-oriented goals

Staff disallows the Companies' stock plan costs related to shareholder-oriented goals because the goals are based on financial measures that primarily benefit shareholders and not ratepayers. The three stock plans are awarded based on the following financial outcomes: 1) the Integrys Restricted Stock Unit Award plan is valued solely using the stock price of Integrys Energy Group, Inc, 2) the Integrys Performance Stock Right Agreement plan is valued using a model comparing Integrys Energy Group, Inc.'s stock price, shareholder returns, total stock return volatility and dividend yield with a peer group and 3) the Integrys NonQualified Stock Option Agreement plan is valued using a model comparing Integrys Energy Group, Inc.'s stock return volatility and dividend yield. Staff Ex. 1.0 at 15-16. The result of Staff's analysis is disallowance of 100% or $3,067,000 (Peoples Gas) and $609,000 (North Shore) of the stock plan costs that the Companies propose to recover in the revenue requirement but have not shown to benefit ratepayers. *Id.*

The Companies oppose this sub-part of Staff's adjustment to remove the incentive compensation costs of its stock-based plans since the "stock plans are designed to attract and retain a qualified and motivated workforce." NS-PGL Ex. JCH-1.0 at 9. However, there is no debate that the stock plans are based solely on financial goals that primarily benefit shareholders. Staff Ex.. 1.0 at 15-16 and Staff Ex. 15.0, Attach. F. The Companies were denied cost recovery of their restricted stock and performance shares plan costs in their last rate cases because they failed to demonstrate cost savings or other direct ratepayer benefit. Staff Ex. 1.0 at 18. The current record similarly lacks a demonstration of cost savings or other direct ratepayer benefit.

<u>Disallowance of capitalized incentive compensation previously disallowed by the Commission</u>

Staff disallows capitalized incentive compensation previously disallowed by the Commission. In the Companies' last rate case, Dockets 07-0241/07-0242 (Consol.), the Commission disallowed a portion of the Companies' capitalized incentive compensation. *In re North Shore Gas Company and The Peoples Gas Light and Coke Company*, Dockets 07-0241/07-0242 (Consol.), Order at 66-67 (Feb. 5, 2008). The Companies did not make any entries, though, to remove the disallowed amount from rate base. Staff Ex. 1.0 at 17. Therefore, the previously disallowed capitalized incentive compensation is included in the test year rate base and should be disallowed in accordance with the Commission's prior order. The Companies agree that they did not make entries to remove disallowed capitalized incentive compensation from rate base denied by the Commission in Dockets 07-0241/0242 (Consol.), but maintain that these amounts should be included in rate base in this proceeding since its appeal remains pending. NS-PGL Ex. JH-2.0 at 16. However, rulings of the Commission remain valid unless and until they are reversed or set aside by a reviewing court. 220 ILCS 5/10-204. Accordingly, the rates set in this case should not include amounts that the Commission has already disallowed from rate base.

<u>AG/CUB/City Incentive Compensation Adjustment</u>

Staff notes that AG/CUB/City witness Effron's adjustment does not include all test year incentive compensation costs, because it does not include costs identified by the Companies later in their responses to discovery. Staff Ex. 15.0 at 18. The Companies did not dispute the calculation of Staff's adjustment. Also, AG/CUB/City advocate a disallowance of 50% of incentive compensation paid directly to the employees of the Companies, and 100% disallowance of incentive compensation allocated from affiliates. AG/CUB/City Ex. 1.0 at 21. Staff is unaware of the Commission strictly using these criteria -- direct payments versus allocations -- as the basis for calculation of an incentive compensation disallowance. Therefore, Staff recommends the Commission adopt Staff's adjustment rather than the AG/CUB/City's adjustment.

d) Commission Analysis and Conclusion

For the most part, the Commission agrees with Staff. Incentive compensation related to financial goals, affiliate goals or shareholder goals should not be recoverable from ratepayers. The Commission has long held that costs related to incentive compensation are recoverable in rates only if the utility demonstrates tangible benefits to ratepayers. *See, e.g., Docket 03-0403* at 15 ("[T]o recover incentive compensation, the plan must confer upon ratepayers specific dollar savings or other tangible benefits. Furthermore, the degree of benefit that accrues directly to ratepayers, rather than to other stakeholders, is a significant factor in determining whether incentive compensation should be recovered in rates."); *Docket 01-0696* at 10 (requiring evidence of "specific dollar savings or any other tangible benefit for the ratepayers"); *Docket 01-0432* at 42-43 ("the Commission has generally disallowed such expenses except where the utility has demonstrated that its incentive compensation plan has reduced expenses and created greater efficiencies in operations. … [I]f a utility is seeking to recover such projected expenses from ratepayers, the utility should demonstrate that its plan can reasonably be expected to provide net benefits to ratepayers."). The utility bears the burden to establish that such tangible benefits accrue to ratepayers, in order to prove that the recovery of incentive compensation costs is just and reasonable. See 220 ILCS 9-201(c).

This long line of Commission precedent was recently affirmed. In ComEd's appeal of the Commission's decision in Docket 05-0597, the court stated that "there is ample precedent making a benefit to ratepayers a condition upon which the recovery of salary-related expense depends" *ComEd Appeal* at 12. The Commission's decision here conforms to this standard.

Staff's adjustments to the executive and non-executive plans are adopted, except for the adjustment for goals unlikely to be achieved. We agree with the Company that these include operational goals that the Commission would like to see achieved, such as reduction in system leaks. Although the goals might not have been achieved in the past, we doubt that cutting the incentive compensation would increase that likelihood. Staff's position does not recognize that the nature of incentive compensation plans is such that there is no guarantee that the goals will be met and the compensation paid to employees. Accordingly, that portion of Staff's adjustment to the executive and non-executive incentive plans is not adopted.

The Commission agrees with Staff that performance goals tied to the Utilities' affiliates do not benefit Illinois ratepayers. Accordingly, Staff's adjustments for affiliate performance are adopted.

Utilities witness Hoover argued that both its Executive and Non-Executive incentive compensation plans are designed to attract and retain highly qualified and motivated employees. NS/PGL Ex. JCH-1.0 at 3, 7. But this reasoning does not demonstrate a sufficient nexus between the expense and customer benefit. The Commission agrees with AG witness Effron that when incentive compensation seeks to achieve goals that primarily benefit shareholders, then it is reasonable to require that shareholders bear the cost of that incentive compensation. This does not imply that the incentive compensation results in excessive or unreasonable salaries. Rather, it is matter of matching the costs and benefits of the programs, so that costs are borne by the beneficiaries. *Id.* Moreover, the *ComEd Appeal* found that attracting good employees was too remote a benefit for ratepayers to support recovery from ratepayers. *ComEd Appeal* at 13*.*

With respect to the Utilities' stock plan, the Commission notes that the stock plan was rejected in the Utilities' last rate case. The record in this proceeding is similarly bereft of evidence of a benefit to ratepayers. Staff's adjustment is adopted.

The Commission agrees with Staff that capitalized incentive compensation previously disallowed by the Commission should be removed from rate base. The Utilities' last rate case might be on appeal, but the decision remains in full force and effect.

The disallowance proposed by AG/CUB/City witness Effron is based on a method not previously adopted by the Commission. The rationale for this proposed method is not explained and, thus, it is not adopted.

2. Non-Union Base Wages Adjustment (Agreed in Part) (Falls in Multiple Categories of O&M)

a) Utilities

Staff and the Utilities agree to certain reductions in the Utilities' non-union base wages that the Utilities accepted in their Rebuttal Testimony, but Staff proposes to reduce even further both Peoples Gas' and North Shore's non-union base wages. Staff's proposal for further decreases lacks merit and should not be adopted.

Staff proposes to reduce the 2010 test year non-union base wages based on a two-step methodology that starts with the 2008 actual amounts and then escalates them for each of 2009 and 2010 using a 2.2% inflation rate, based on general Consumer Price Index ("CPI") inflation data that became available in May 2009. Staff Ex. 15.0 at 19-20 and Scheds. 15.8N and 15.8P.

The Utilities note that they increased their non-union base wages for 2009 in February 2009, three months before Staff's data became available. NS-PGL Ex. JCH-2.0 at 5. Utilities witness Hoover testified that it was inappropriate to "retroactive[ly]" look back on the February 2009 increases based on general CPI data from May 2009, and that the lower level of wage increases that Staff hypothesizes would result in non-competitive salaries. *Id*. at 5.

The Utilities believe that Staff's proposal also is flawed as to both 2009 and 2010 because of its reliance on general CPI information and its rejection of labor market data. Mr. Hoover testified that reliance on that general CPI data for this purpose is not realistic given the evidence presented. NS-PGL Ex. JCH-1.0 at 9. The Utilities' forecasts relied on market data provided by the World at Work 2008-2009 Salary Budget Survey and input from Towers Perrin human resources consultants, subject to the reductions made as part of the cost control measures. *Id.* "The World At Work Salary Budget Survey is a well-known compensation tool that reports results of annually surveyed information on planned increases for the following budget year. They use information submitted by corporations in all industries and reported in the aggregate to assist in corporate salary budget planning." *Id.* at 10. There is no valid basis for rejecting labor market data actually used by the Utilities in making human resources decisions and supported by a human resources expert in favor of general CPI information supported by a witness who is not an expert in this subject. That the Commission, based on other evidentiary records, has relied on general CPI information in other cases in determining salaries and wages adjustments is not a reasonable basis for doing so given the evidence in the instant cases.

Finally, the Utilities assert that Mr. Hoover's testimony that the increases proposed by Staff for both 2009 and 2010 would result in non-competitive salaries (NS-PGL Ex. JCH-1.0 at 10; NS-PGL Ex. JCH-3.0 at 5) is uncontradicted.

Staff's proposal for further reductions in the Utilities' non-union base wages, beyond those accepted in the Utilities' Rebuttal Testimony, the Utilities assert it is not justified and should be rejected.

b) Staff

Staff witness Hathhorn's proposed adjustments to reduce each Company's rate base and operating expenses to reflect test year non-union base wages at a more reasonable amount in light of the current economic environment. Staff Ex. 15.0, Schedules 15.8 P and N, Non-Union Wages Adjustment. Staff's adjustment is calculated using the 2009-2013 Consumer Price Index ("CPI") inflation rate of 2.2% as forecasted by the *Survey of Professional Forecasters* ("*Survey*"). Staff Ex. 1.0 at 26, fn. 3.

Staff used the Survey rate to escalate the Companies' 2008 actual non-union base wages to determine test year non-union base wages. This compares to the Companies' forecast increase of 4.2% in both calendar years 2009 and 2010. *Id.* at 27. The Companies state that their projected annual increases were forecasted using market data provided by the World at Work 2008-2009 Salary Budget Survey and with input from Towers Perrin consultants. NS-PGL Ex. JCH-1.0 at 9-10. The 2009 market data was received by the Companies during the spring/summer 2008. Staff Ex. 1.0 at 27. The test year percentage of 4.2% also appears overstated in comparison to the years 2006 through 2008 inclusive, wherein the percentage increase in non-union base wages was 3.0%, 3.5%, and 3.8%, respectively. Staff Ex. 1.0 at 27.

An update to the salary survey upon which the Companies rely for their wages forecast shows the unreasonableness of their decision to rely upon pre-economic downturn data. A July 8, 2009 press release from World at Work discussed the World at Work 36th Annual Salary Budget Survey which collected survey data in April 2009. The press release states that corporate salary budget increases have dropped to historic lows, and that at 2.2%, the 2009 increase is the smallest in the survey's history and 1.7 percentage points below the 3.9% that had been projected in the previous year's report. Finally, the press release stated that the projected budget increase for salaries for 2010 is 2.8%. Staff Ex. 15.0 at 21. Thus, the very source upon which the Companies rely upon is more supportive of Staff's proposal rather than the Companies' proposal.

The Companies discuss in Direct Testimony their consideration of the challenging economic times. The Companies further state the forecasted increase amounts are prudent and reasonable, and necessary to remain competitive in the industry. NS-PGL Ex. JCH-1.0 at 11. Staff notes that the Companies would have rates set upon increases based on a salary study conducted prior to the current economic downturn. The Companies' response to the recent changes in the economy regarding its wage increases does not demonstrate reasonableness for rate setting. The Companies state they cancelled the 2008 annual merit increase but replaced it with a "general wage delayed" increase covering a 14-month time period. NS-PGL Ex. JCH-1.0 at 10. The Companies have not demonstrated why a two month salary increase delay based upon pre-economic downturn data is reasonable for ratepayers to pay during this economic downturn.

The Commission has adopted adjustments to test year wages using an inflation factor in the past. In Docket 91-0193, the Commission adopted a Staff adjustment to Central Illinois Public Service Company's proposed wage increases using the former Wharton Econometric Forecasting Associates ("WEFA") Economic Outlook. *In re Central Illinois Public Service Company*, Docket 91-0193, Order at 70 (Mar. 18, 1992). A similar adjustment was adopted by the Commission for ComEd. *In re Commonwealth Edison Co.*, Docket 90-0169, Order at 38 (Mar. 8, 1991). The Commission also adopted a Staff adjustment based upon an updated WEFA index in Peoples Gas' Docket 90-0007. *In re The Peoples Gas Light and Coke Co.*, Docket 90-0007, Order at 19, (Nov. 9, 1990). The issue in the three previous cases was contested; the Commission also adopted an uncontested adjustment based upon the WEFA inflation indicator for IAWC. *In re Illinois American Water Co.*, Docket 92-0116, Order at 14, Feb. 9, 1993).

c) Commission Analysis and Conclusion

The Commission finds that it is appropriate to update 2008 actuals by 2.2% for 2009 as proposed by Staff and supported by the updated World at Work survey and increase those by 2.8% for 2010 based on the World at Work 2010 forecast. Moreover, this approach is consistent with prior decisions, as noted by Staff. The Utilities' proposal does not account for the current economic situation.

3. Head Counts (Falls in Multiple Categories of O&M)

a) Utilities

AG/CUB witness Effron proposes a disallowance based on his conclusion that Peoples Gas and North Shore will not have as many employees as they forecast. As of mid-2009, Peoples Gas' employee headcount had not risen appreciably from 2008 levels, so Mr. Effron theorized that it also would not increase by the test year, 2010. AG/CUB/City Ex. 1.0 at 17-18; AG/CUB Ex. 4.0 at 8.

The Utilities assert that Mr. Effron's "trend line" analysis, without more, cannot overcome Peoples Gas' testimony indicating that it would be hiring more employees. North Shore did not submit additional evidence, but it also contests this adjustment. The difference between North Shore's planned headcount and Mr. Effron's prediction is only three employees, amounting to a disallowance of $137,000. AG/CUB/City Ex. 1.0 at 19. Aside from the budget, Peoples Gas' Vice President of Gas Operations testified that Peoples Gas had specific plans to bring on new employees, in large part to comply with Commission orders. NS-PGL Ex. ED-2.0 at 6 – 7. In fact, 36 of the 47 new employees will directly relate to addressing the safety recommendations of Liberty Consulting in their August 2008 report. *Id*. Mr. Doerk was able to update the status of the new hires in his Rebuttal Testimony drafted in August. Since June 2009 (and therefore post-dating the information on which Mr. Effron relied), Peoples Gas has now hired 27 new Operations Apprentices and 5 new Operations Specialists, and is interviewing additional candidates. NS-PGL Ex. ED-3.0 at 3 – 4. That demonstrates that Peoples Gas' forecast is realistic, that it is not going to ignore the Liberty recommendations, and that Mr. Effron's proposed decrease should be rejected.

b) AG

AG/CUB/City witness Effron proposed a reduction to the Companies' forecasts of the number of employees in the 2010 test year. AG/CUB/City Ex. 1.0 at 17. As explained by Mr. Effron, Peoples Gas is forecasting that the number of employees in 2010 will be 1139. As of early 2009, the actual number of employees was about 1080, and that number does not appear to be increasing. *Id.* In the present economic circumstances, Mr. Effron concluded that the increase in the number of employees being forecasted by PGL is uncertain. Similarly, North Shore is forecasting 170 employees in the 2010 test year. *Id.* at 18. This is an increase over the 167 employees in the early months of 2009, which, like the Peoples Gas employee complement, does not appear to be increasing. *Id.* Therefore, Mr. Effron concluded that the number of test year employees and the payroll expense forecasted by PGL and NS should be modified. *Id.*

Based on the response to Data Requests PGL AG 3.18 and PGL AG 3.19, the actual number of PGL employees in the last half of 2008 and the first three months of 2009 was relatively steady at about 1,080 (although the actual number of employees in March 2009, the last month shown was slightly lower at 1,075). *Id.* Mr. Effron recommended that, based on that response, the PGL 2010 test year payroll expense be adjusted to reflect 1,080 employees rather than the PGL forecast of 1,139. *Id.*

For North Shore, company data showed that the actual number of NS employees in the last half of 2008 and the first three months of 2009 was relatively steady at about 167 (the exact number from September 2008 through March 2009). Based on this data, Mr. Effron recommended that the NS 2010 test year payroll expense be adjusted to reflect 167 employees rather than the NS forecast of 170. *Id.*

The effect of the AG's proposed adjustments to the forecasted number of employees in the 2010 test year reduces the forecasted test year operation and maintenance expense by $2,987,000. *Id.* at 19. Mr. Effron's proposed adjustment to the NS test year employee complement reduces the forecasted test year operation and maintenance expense by $137,000 (AG/CUB/City Ex. 1.1 (NS), 1.2 (PGL) Schedule C-2.1).

In response to Mr. Effron's proposed adjustment, Utilities witness Doerk argued that Peoples Gas still intends to increase its headcount to the forecasted level in order to satisfy its regulatory obligations and, as such, the proposed adjustment should be rejected. As pointed out by Mr. Effron, however, the Companies' responses to AG data requests contradict that opinion. Specifically, the Companies' responses to AG Data Request 7.08 updated PGL employee levels through June 2009. AG/CUB/City Ex. 4.0 at 8. For the three months April 2009 through June 2009, the average level of total full time equivalent employees was 1,074. This is actually lower than the head count of 1,080 on which Mr. Effron based his proposed adjustment. *Id.*

In Surrebuttal Testimony, NS/PGL witness Doerk opined that since June of 2009, 27 employees have been hired. NS/PGL Ex. ED-3.0 at 3. However, the AG argues that the Companies regularly experience turnover through retirements or employees leaving. Also, the AG notes that although Surrebuttal Testimony was filed on August 17, 2009, the Companies never presented evidence on the actual PGL/NS employee complement in July of 2009 to verify that the June hires actually increased the net employee numbers of these two companies.

For all of these reasons, the AG believes Commission should adopt the adjustment to forecasted employee levels presented by Mr. Effron.

c) Staff

In regard to the adjustment to headcount for Peoples Gas, Staff witness Hathhorn testified that she agreed with the position of Peoples Gas that its increased forecast headcount is designed to address specific Liberty Audit recommendations. NS-PGL Ex. ED-2.0 at 6-7 and Staff Ex. 15.0 at 32. In regard to the adjustment of headcount for North Shore, Staff is not aware of any response from the Company other than simply not reflecting the adjustment in its rebuttal schedules; therefore, Staff has no opinion on whether it should be adopted. *Id.*

d) Commission Analysis and Conclusion

The Commission accepts Peoples Gas' proposed head count becausethe Commission finds that it is supported by the evidence and also not contested by Staff. The forecast is designed to address specific Liberty Audit recommendations. North Shore did not provide evidence in response to the AG's adjustment. The Commission also adopts AG witness Effron's head count adjustment for North Shore.

4. Distribution Expenses - Liberty Audit Adjustment

a) Utilities

Staff proposes a reduction of $5 million of 2010 test year operating expenses based on the Commission's order in *Illinois Commerce Comm'n on its Own Motion v. The Peoples Gas Light and Coke Co.,* Docket 06-0311 (Order Dec. 20, 2006) ("*06-0311 Order*"), at 6, which stated, in brief, that Peoples Gas would not recover, in its next rate case, costs solely attributable to not performing corrosion inspections in a timely manner or incremental costs due solely to violations of the Pipeline Safety Act. The Utilities urge that the proposed disallowance be rejected for two reasons. First, the

Utilities believe the record is clear that Peoples Gas did not include any such incremental costs in its test year operating expenses. *See* NS-PGL Ex. ED-2.0 at 7. Second, the disallowance is "based" on an arbitrary figure.

In Docket 06-0311, the Commission found that Peoples Gas needed to improve its corrosion protection activities. The case ended with a stipulation between Peoples Gas and Staff that formed the basis for the Commission's final Order. Using the agreed language from the stipulation, the Commission held, in relevant part, as follows:

> pursuant to its agreement in the Stipulation, Peoples Gas shall not seek recovery, in any future rate or reconciliation proceeding before the Commission, of costs or expenses solely attributable to Peoples Gas' not performing corrosion inspections in a timely manner, as specified in paragraph 4 above, or any incremental costs caused solely by violation of the Illinois Gas Pipeline Safety Act or its implementing regulations ("the Act") discovered by the Commission's consultant retained pursuant to the Memorandum of Understanding, and which are over and above the prudent and reasonable costs necessary to comply with the Act. Peoples Gas shall operate an internal tracking mechanism to account for any such incremental costs.

06-0311 Order at Ordering Paragraph 11.

The consultant referred to in Findings and Ordering paragraph (11) was provided for in Findings and Ordering paragraph (6) and Stipulation section 9(C). *Id*. at 5, 8. The Commission subsequently retained the Liberty Consulting Group as that consultant. Liberty's investigation began in May 2007. Staff Ex. 23.0 at Attachment A, p. ES-1 and p. 2. Liberty issued its final report on August 14, 2008. *Id*. at Attachment A, cover page. Peoples Gas briefly retained the Huron Consulting Group to help set up a project management office to address Liberty's recommendations. NS-PGL Ex. 3.0 at 10.

In response to Staff's allegations in Docket 06-0311 and to the Commission's order, Peoples Gas undertook to improve its corrosion protection program, among other things hiring additional staff with better and more specific training. Staff Ex. 23 at 9 – 10; NS-PGL Ex. 3.0 at 8 – 9. The Staff and Peoples Gas witnesses agreed that these steps have improved Peoples Gas' compliance with the Pipeline Safety Act. Tr. at 942 – 945; NS-PGL Ex. ED-3.0 at 8. No witness cited any outages, reliability problems, fires, explosions, leaks, or other similar problems caused by Pipeline Safety Act violations since the final order in Docket 06-0311. Indeed, Mr. Doerk, who said it would definitely come to his attention as head of operations if such problems occurred, affirmatively stated that there were no such events. NS-PGL Ex. ED-2.0 at 7 – 8; Tr. at 639 – 640.

Staff's proposed disallowance is based on the allegation that there must be costs in Peoples Gas' <u>2010</u> test year operating expenses solely attributable to not performing corrosion inspections in a timely manner or incremental costs due solely to violations of the Pipeline Safety Act discovered by Liberty. However, other than pointing to fees of Liberty and Huron related to the Liberty Audit, which Peoples Gas already has agreed should not be included in, and already has removed from, its revenue requirement, Staff has pointed to no instance in which costs prohibited from recovery are included in the test year costs. That is because none exist.

Given these facts, no disallowance is proper as there were no incremental costs to track and write off. Peoples Gas asserts that if it did have something go wrong, due to a violation of the Pipeline Safety Act, and it cost incremental money to fix it, that money would have to be tracked. Tr. at 941 – 942. If Peoples Gas acted prudently and reasonably to come into compliance, for example by hiring extra inspectors, the salaries of those inspectors would *not* need to be tracked and excluded. Tr. at 942. According to Peoples Gas, the evidence shows that the only costs Peoples Gas incurred were these type of reasonable and prudent costs of complying with the Pipeline Safety Act. NS-PGL Ex. ED-2.0 at 7; NS-PGL Ex. ED-3.0 at 7. For each of the things cited by Mr. Burk as a violation based on the findings of the Liberty Audit, Mr. Burk agreed that Peoples Gas addressed those violations using reasonable means to comply with the Pipeline Safety Act. Tr. at 942 – 945. Utilities witness Doerk testified at the hearing that Peoples Gas caught up on corrosion inspections and corrective actions in 2005 and since then has hired additional corrosion control inspectors but no more than the number that was prudent and reasonable. Tr. at 640-641. What Peoples Gas did not do was to let the problems go, leading to incremental costs attributable to violations. Accordingly, there were no incremental expenses to track, and no incremental expenses to exclude from test year operating expenses.

Ms. Hathhorn testified in support of Staff's proposed disallowance. Noting that there was no tracking mechanism in place, and therefore no quantification of costs, she arbitrarily decided to make a disallowance of 5% of Peoples Gas' entire test year distribution costs. She appears to conclude that the Commission's Order in Docket 06-0311 required that Peoples Gas develop a tracking mechanism even if there were no relevant costs to track. Peoples Gas disagrees with this interpretation. If relevant costs were incurred a tracking mechanism would have been instituted. There is no evidence in the record to support a need for a tracking mechanism or any such disallowance, or suggesting a relationship between all distribution costs and the costs covered by the stipulation in Docket 06-0311. Her proposed disallowance is therefore improper. The Utilities argue that she misunderstood the scope of the expenses to be excluded under the Order. She erroneously described her disallowance as "costs to come into compliance with the Liberty audit findings," "test year costs resulting from the Liberty Audit," and "costs to comply with the Liberty Audit." Staff Ex. 1.0 at 34 – 35. As Mr. Burk agreed, Peoples Gas could incur costs to come into compliance, but so long as those costs were reasonable and prudent, they would not be disallowed. Tr. at 941 – 942. The Utilities assert that Staff's disallowance should be rejected.

In response to Staff's argument regarding the Commission's Order in *In re Central Illinois Light Company*, Docket 94-0040, 1994 Ill. PUC Lexis 577 (Order Dec. 12, 1994) ("*CILCO 94-0040*"). The Utilities note that the facts in that case are very different, and the principle that was stated and applied by both Staff and the Commission in that case supports Peoples Gas here, not Staff.

In *CILCO 94-0040*, based on the evidence in the record in that Docket, the Commission found both that the utility had been imprudent and that the utility's imprudence had caused significant incremental amounts to be spent that otherwise would not have been spent. *CILCO 94-0040* at 24-25. Staff there submitted evidence, and the Commission specifically found, that the utility's imprudence required the utility to spend more to fix the problems than the utility would have spent if it had acted prudently. *CILCO 94-0040* at **25, 27, 29-30. Accordingly, Staff proposed to disallow the incremental portion of the amounts spent by the utility that were due to imprudence, and the Commission agreed that that was the correct measure of the disallowance. *CILCO 94-0040* at **30-35, 40-42. The Commission expressly rejected an intervenor's contention that the entire amount spent (apart from a certain amount already scheduled to be spent), rather than the incremental amount spent due to the imprudence, should be disallowed, finding not only that disallowing more than the incremental amount was unwarranted but also that it would create an incentive to put off dealing with dangerous situations. *CILCO 94-0040* at **37-41. The Commission's adoption and application of the principle that only incremental amounts due to the imprudence should be disallowed could not be clearer.

The Utilities state that, unlike CILCO in *CILCO 94-0040*, what Peoples Gas did not do was to ignore the problems that were discovered in a way that led to incremental costs attributable to untimely inspections or to violations of the Pipeline Safety Act over and above the level of prudent and reasonable costs. Other than the fees of Liberty and Huron that Peoples Gas already has removed from its revenue requirement, as referenced earlier, Staff can point to no incremental expense that is in Peoples Gas' revenue requirement that is due solely to untimely corrosion inspections or to violations of that statute. The evidence shows that there is none, as discussed above.

Finally, Staff's argument for its proposed disallowance, and its methodology for calculating the disallowance, are based upon yet another faulty premise, *i.e.*, that there were incremental costs incurred in 2008 over and above the level of costs that was prudently and reasonably incurred to comply with the Pipeline Safety Act and that those incremental costs were incorporated in the 2010 test year forecast. Staff states in part as follows:

> Much of the work associated with the audit was performed in 2008, and the [Liberty] audit report was issued in August 2008. These facts are uncontested as Mr. Doerk's testimony confirms that the Company started responding to the Liberty audit findings during the audit period. [Doerk Sur.,] NS-PGL Ex. ED-3.0, p. 8, lines 163-164 and p. 9, lines 184-186. In addition, as explained above, other actions to address the violations identified in the *06-0311 Order* occurred in 2008.

Staff Init. Br. at 80-81.

That statement only further demonstrates that Staff's proposal, and its approach to calculating its disallowance, are without merit. As that statement illustrates, Staff's proposal and the calculation of its disallowance, equate responding to Liberty's findings and recommendations with what is prohibited from recovery under the *06-0311 Order*. That is wrong. The *06-0311 Order* provides for disallowance if and only if there are incremental costs due to untimely inspections or violations of the Pipeline Safety Act discovered by Liberty above the level of prudent and reasonable costs, as discussed earlier.

Moreover, an examination of the testimony cited by Staff above shows that it refutes, rather than supports, the existence of any such incremental costs. In Surrebuttal, Mr. Doerk states: “Peoples Gas was proactive in addressing most of the Liberty recommendations related to corrosion control before the final Liberty investigation report was issued.” NS-PGL Ex. ED-3.0 at 8. The next two sentences state: “Responsibility for the corrosion control function has been centralized, and, as Mr. Burk acknowledged, the inspections and trouble shooting activities have been reassigned to dedicated, qualified technicians, and many new highly qualified technicians have been hired. Since these steps were required to comply with the [Pipeline Safety] Act, the related costs cannot be considered over and above prudent and necessary to comply with the Act.” *Id*. at 8-9. The Surrebuttal also discusses that Peoples Gas hired one contractor for two months in 2008 to help address the most difficult corrosion protection cases. *Id*. at 9. The immediately following sentences of the Surrebuttal once again explain, however, that this did not involve costs over and above those that were prudent and necessary to comply with the Pipeline Safety Act. *Id*. at 9-10. As noted earlier, Mr. Doerk’s Surrebuttal went through each of the items raised by Mr. Burk’s rebuttal and explained why they did not lead to such incremental costs. *Id*. at 7-10.

Furthermore, nowhere in Mr. Doerk’s testimony does he state that all the work pertaining the *06-0311 Order* or even the Liberty Audit was performed between January 1, 2008 and June 30, 2008 (the period of actual data for 2008 that was used in developing the 2010 forecast). The evidence demonstrates the opposite. First, the “catch-up” work that resulted from the 2004 and 2005 Staff audits was completed in 2005, not 2008. Tr. at 630-631, 634. Second, Liberty began its audit in May 2007, and Peoples Gas began responding before the Liberty’s final report was issued, as noted earlier. Finally, again, Mr. Doerk’s Surrebuttal addressed the actions taken in 2008 and showed that they did not result in incremental costs above the level of prudent and reasonable costs.

To be clear, the record does reflect that in 2008, in response to certain of the Liberty Audit recommendations, Peoples Gas increased its employee headcount. PGL CMG-1.0 Rev at 16. However, even Staff witness Burk recognized that these costs were reasonable and prudent. Tr. at 944-945.

The Utilities assert that to disallow prudent and reasonable costs of coming into compliance with the Pipeline Safety Act would be contrary to the *06-0311 Order*. Also, to disallow prudent and reasonable costs of coming into compliance with the Pipeline Safety Act also would be contrary to public policy. NS-PGL Ex. JFS-2.0 at 14, 15. *See also CILCO 94-0040* at **37-41.

Finally, Staff’s selection of the very large amount of 5% of total 2010 test year distribution operating and maintenance expenses, which translates to $4,961,000, as the quantification of its proposed disallowance (*see* Staff Ex. 1.0 at 35) is arbitrary, unreasonable, and excessive. The Utilities do not agree with Staff’s assertion that the 5% figure is “reasonable” because 2008 costs were escalated by 2.0% and 1.8% for

2009 and 2010 for forecasting purposes (*Id*. at 35) makes no sense. There is no logical relationship between the percentage by which total costs increased in 2009 and 2010 and any assumption about how much costs of a particular kind, if any, existed in 2008 in the first place to be escalated. NS-PGL Ex. JFS-2.0 at 15. Staff's attempt to criticize Peoples Gas for not having a tracking mechanism does not justify Staff's approach. The *06-0311 Order* expressly required tracking of defined incremental costs. *06-0311 Order* at 8 (quoted earlier). There were no such costs, as the earlier discussion shows.

Utilities witness Gregor, in her Direct Testimony, addressed the main drivers of the increases in Peoples Gas' distribution operations and maintenance from 2007 to 2010. PGL Ex. CMG-1.0 Rev. at 16:335-351. That testimony is uncontradicted. The only driver that was related to the subject at hand here was the increased headcount related to the implementation of Liberty's recommendations. The testimony of Utilities witness Doerk and Staff witness Burk supports the conclusion that the increased headcount is prudent and reasonable, as discussed earlier. Accordingly, the Utilities maintain that there is no factual basis for any hypothesized incremental costs that should be disallowed.

Therefore, for all the reasons stated herein the Utilities urge the Commission to reject Staff's proposed adjustment relating to the Commission's *06-0311 Order*.

b) Staff

Staff witness Hathhorn proposed to disallow $4,961,000 in test year operating expenses prohibited from rate recovery by the Commission's *06-0311 Order* entered pursuant to a Stipulation and Memorandum of Understanding ("MOU") among the parties to that docket.

The *06-0311 Order* prohibited Peoples Gas from seeking recovery in any future rate or reconciliation proceeding "of costs or expenses solely attributable to [its] not performing corrosion inspections in a timely manner, as specified in [Findings and Ordering] paragraph 4 …, or any incremental costs caused solely by violation of the Illinois Gas Pipeline Safety Act or its implementing regulations ("the Act") discovered by the Commission's consultant …, and which are over and above the prudent and reasonable costs necessary to comply with the Act"; required Peoples Gas to "operate an internal tracking mechanism to account for any such incremental costs"; and prohibited Peoples Gas from recovering "any fees paid to the consultants retained by Peoples Gas or by the … Commission … in connection with or as a result of ICC Docket 06-0311." *06-0311 Order* at 7-8. The Liberty Consulting Group was retained as the Commission's consultant and investigated and reported on Peoples Gas' pipeline safety program, providing 66 recommendations ("Liberty Audit"). Staff Ex. 23.0, Attachment A.

Ms. Hathhorn's proposed adjustment is for all costs that come within the above-described cost recovery prohibitions set forth in the *06-0311 Order*, including (i) costs attributable to the acts or omissions resulting in the Commission's finding that Peoples Gas failed to comply with corrosion inspection and related pipeline safety regulations, (ii) incremental costs caused solely by violation of the Pipeline Safety Act or its implementing regulations discovered by the Commission's consultant (Liberty

Consulting) and which are over and above the prudent and reasonable costs necessary to comply with the Act, and (iii) costs for fees paid to consultants retained by Peoples Gas or by the Commission in connection with or as a result of Docket 06-0311. All of the costs proposed for disallowance are collectively referred to in this brief and the outline as Liberty Audit-Related Expenses.

The 06-0311 Order Cost Recovery Prohibition

The Commission commenced Docket 06-0311 "to determine whether … Peoples Gas … failed to: 1) comply with the cathodic protection inspection requirements of 49 CFR § 192.465(a); 2) test corrosion control segments on an annual and/or ten-year testing schedule as required by Commission rules; 3) take prompt remedial action to correct any deficiencies indicated by the monitoring as required by 49 CFR § 192.465(d); and 4) comply with the requirement of 49 CFR § 192.13(c) by failing to follow its Corrosion Control Policy, Operation and Maintenance Plan." *06-0311 Order* at 1. Pursuant to the Stipulation and record evidence, the Commission in Docket 06-0311 found that Peoples Gas had indeed failed to comply with various pipeline safety regulations in Findings and Ordering paragraph (4):

> (4) as acknowledged by Peoples Gas in the Stipulation, and as supported by the evidence, Peoples Gas was not in compliance with applicable federal and state pipeline safety regulations -- *viz*., 49 CFR §192.13(c) and 49 CFR §192.465(a) and (d), adopted by the Commission at 83 Ill. Admin. Code 590 pursuant to Section 3 of the Illinois Gas Pipeline Safety Act (220 ILCS 20/3) -- respecting cathodic protection inspection and remediation and the requirement to maintain and follow procedures and programs, by being late in conducting corrosion testing on certain service pipes and main segments that were due for inspection before and during 2003 and 2004, and by failing to perform corrective action during 2004 and 2005 at test points on certain service pipes and main segments found to be out of compliance during in 2003 and 2004**;**

06-0311 Order at 7.

In addition to imposing a penalty for the above-described violations (*Id.* at 7), the Commission imposed rate recovery limitations and cost tracking requirements on Peoples Gas in Findings and Ordering paragraph (11). While there is not a general discussion of these recovery limitations in the *06-0311 Order*, the Commission's intent is clear and reasonable: ratepayers should not pay for any cost increase that results from the Company's failure to comply with applicable pipeline safety regulations.

The failure to comply with applicable pipeline safety regulations clearly constitutes an imprudent act or omission by Company management. The Commission properly found that additional or incremental costs resulting from the compliance violations identified in the *06-0311 Order,* as well as other compliance violations discovered by the Commission's consultant, should not be recovered from ratepayers. Staff argues that the Commission may find a cost that would otherwise be prudent and reasonable to be an imprudently incurred cost if the reasons that necessitated the purchase or expenditure are imprudent management decisions, acts or omissions. The

Commission's decision to bar recovery of additional costs incurred as a result of Peoples Gas' failure to comply with applicable pipeline safety regulations is proper since the failure to comply is not prudent and the costs caused by those imprudent acts or omissions cannot constitute prudently incurred costs. The fact that those costs are necessary to come into compliance with applicable pipeline safety regulations (and would otherwise be considered prudent when viewed from that perspective) does not excuse the Company from the consequences of its imprudent acts or omissions; namely, the non-recovery of additional costs incurred as a result of its imprudent acts or omissions.

In *Business & Professional People for Public Interest v. Illinois Commerce Comm'n*, 171 Ill. App. 3d 948 (1st Dist. 1988) ("*BPI*") ComEdappealed a Commission's determination in a uniform fuel adjustment clause reconciliation proceeding that over $70 million of costs should be refunded to customers because they were not prudently incurred. *Id*. at 955-956. ComEd argued that the Commission erred in making its prudence determination by looking at plant productivity (i.e., the failure of the LaSalle 1 nuclear power plant to operate at forecasted capacity) to determine the prudence of purchased fuel and power (i.e., fuel and power needed to generate or obtain electricity to replace power not generated due to the reduced productivity of LaSalle 1). *Id*. at 956-958. The court upheld the Commission's decision and explained that ComEd's view on the narrow scope of a prudence review was contrary to the requirement for just and reasonable rates:

> If, in a fuel reconciliation proceeding, the Commission could not examine the reasons that necessitated a fuel purchase, the prudence standard would have no effect on ensuring a just and reasonable rate as required by sections 36 and 41 of the Act; a utility could generate electricity in any manner it chose, efficiently or inefficiently, and the Commission would be limited to determining merely whether the utility paid a prudent price for the fuel.

(*Id*. at 958) Thus, while the costs of reasonably priced fuel needed to generate electricity for a utility's customers would generally be considered prudently incurred costs, such costs are not prudently incurred if an imprudent management act or omission caused or contributed to the need for such fuel. Thus, the court held "that the Commission was within its statutory authority when it applied the prudence standard to the reasons for the purchases, and not only to the actual purchase transactions." *Id*. at 959.

The Commission applied this same logic to exclude from Central Illinois Light Company's ("CILCO") rate base additional costs incurred to replace cast iron mains on an expedited basis because the need for expedited replacement resulted from CILCO's imprudent failure to adequately maintain its Springfield cast iron distribution system. *In re Central Illinois Light Company*, ICC Docket No. 94-0040, 1994 Ill. PUC LEXIS 577, 12-42; 158 P.U.R.4th 1 (Order, Dec. 12, 1994). Specifically, the Commission found that CILCO had acted imprudently with respect to its management of gas leaks:

> The Commission concludes that the weight of the evidence leads to the inexorable conclusion that CILCO, for an unspecified period of time prior

> to the discovery of gas in Springfield manholes by Commission personnel in the spring of 1992, had been engaged in a systematic course of conduct intended to underreport the number and severity of gas leaks occurring on its Springfield cast iron distribution system. The Commission further finds that this course of conduct led to the existence of a substantial threat to public safety, which necessitated the immediate and accelerated replacement of the majority of the cast iron system and the expenditure of significant sums that would not have been spent but for CILCO's imprudence.

Id. at 24-25. The Commission then concluded that this imprudence necessitated disallowance of some of the costs of replacing the cast iron system:

> The Commission … finds that allowing the Springfield system to deteriorate to the point of creating a public safety hazard necessitated an accelerated renewal program which led to a level of expenditures that would not ordinarily have been required had CILCO been conducting business in a reasonably prudent manner.
>
> The Commission is of the opinion that such a course of conduct requires the disallowance of some of the expenses associated with the Springfield renewal program….

Id. at 29-30. The Commission rejected arguments that sought to disallow all costs, instead finding that "the disallowances should be imposed only to the extent that the expenses and investment exceed the levels that would have been incurred absent imprudence on the part of CILCO." *Id.* at 40. Staff calculated the additional costs by "comparing the present value of the amount actually expended by CILCO on the renewal program, with the present value of the total amount that would have been expended had CILCO undertaken an eight year renewal program beginning in 1994." *Id*. at 30. The Commission accepted this methodology, with a modification to the discount rate proposed by other parties. *Id*. at 30-35, 40-42.

The reasoning and analysis in CILCO is applicable here. Peoples Gas' failure to perform corrosion inspections and related maintenance caused a certain level of accelerated and additional activities to come into compliance. The same analysis holds for additional violations discovered by the Commission's consultant. To the extent that these costs exceed the costs that would have been incurred without the Company's imprudent failure to comply with applicable pipeline safety regulations, those costs constitute imprudently incurred costs for which recovery must be denied. The arguments by the Companies witnesses, discussed below, that no imprudent or incremental costs exists because all costs were incurred to come into compliance ignores the law and the Commission's order as discussed above.

<u>Staff's Proposed Disallowances</u>

Peoples Gas included $540,000 in test year fees for Liberty Consulting Group and Huron Consulting Group related to the Liberty Audit follow up work, even though such expenses were prohibited to be included in the test year by the Stipulation and Commission Order. Staff Ex. 1.0 at 32-33. Staff contends that the existence and inclusion of prohibited expenses is not an isolated event and notes the Company's failure to track costs. However, Peoples Gas maintains that "No such costs have been identified so no tracking system has been required." Peoples Gas further asserts that there were no such charges as described in Findings and Ordering paragraphs (4) and (11) for 2008, 2009, or the test year. *Id*.

The Company also states that "Liberty Consulting has not identified any violations of the Illinois Gas Pipeline Safety Act ("the Act") or its implementing regulations as a result of their investigation of Peoples Gas' pipeline safety practices. Therefore, no incremental costs have been incurred above prudent and reasonable costs necessary to comply with the Act." NS-PGL Ex. ED-2.0 at 7. Staff witness Burk refuted the Company's position by identifying a number of code violations discovered by the Liberty Audit. *See*, Staff Ex. 23.0. Company witness Doerk does not challenge Mr. Burk's interpretation of the selected Liberty Audit conclusions as code violations. NS-PGL Ex. ED-3.0 at 7. Therefore, the premise for the Company's statement above is unsustainable and must be rejected.

Company witness Schott similarly states that "[b]ased on the rebuttal testimony of Mr. Doerk, there have been no known non-performance or violations since the date of that Order, therefore no such incremental costs have been incurred. It would have been a waste of resources to develop a tracking mechanism for such costs where no such costs existed." NS-PGL Ex. JFS-2.0 at 14. With respect to "non-performance", it has already been determined in Docket 06-0311 that Peoples Gas failed to follow cathodic protection inspection and remediation requirements in a timely manner, as acknowledged by Peoples Gas in Finding (4) quoted above. Staff Ex. 1.0 at 25.

The *06-0311 Order* prohibits Peoples Gas from seeking recovery of "costs or expenses solely attributable to" these violations. *06-0311 Order* at 8. The assertion that there have been no incremental costs from "non-performance" because there has allegedly been "no known non-performance … since the date of that Order" is illogical. The *06-0311 Order* clearly prohibits recovery of costs or expenses incurred solely as a result of Peoples Gas' non-performance before entry of the order. Peoples Gas cannot credibly dispute that it incurred costs or expenses after the date of the *06-0311 Order* to perform cathodic protection inspection and remediation requirements related to its pre-order violations. The question is whether and to what extent those costs or expenses were solely attributable to the earlier non-performance. This task could have been relatively easy and straight-forward if Peoples Gas had implemented a tracking system as ordered by the Commission. While Staff cannot directly calculate the amount of costs or expenses solely attributable to Peoples Gas' pre-order non- performance because of Peoples Gas' failure to track, Staff is confident that costs or expense for which recovery is prohibited did occur and are reflected in the test year.

As Staff witness Burk explained in his Rebuttal Testimony, Peoples Gas' non-compliance resulted in a backlog of required pending corrective actions and Peoples Gas hired contractors to perform troubleshooting and perform corrective actions in 2008. Staff Ex. 23.0 at 8-10. The 2010 future test year costs utilized in this case are based on extrapolations and escalations of 2008 costs. Staff Ex. 15.0 at 26. The additional costs incurred in 2008 to eliminate the backlog (in comparison to the costs that would have been incurred in 2008 without the prior violations) are imprudently incurred costs for which recovery is prohibited under the *06-0311 Order*. This is only one example of an additional cost attributable to Peoples Gas' pre-order violations. Other examples of additional costs attributable solely to the violations would be costs for re-performing work improperly performed the first time or any increased costs of performing work in 2008 versus the earlier period when it should have been performed.

As noted above and explained in more detail in the testimony of Staff witness Burk, violations of the Pipeline Safety Act and its implementing regulations were discovered by the Commission's consultant. Once again, costs to remedy those violations should have been tracked by the Company pursuant to the 06-0311 Order so that incremental costs caused solely by those violations could be identified. Because of the Company's failure to implement a tracking mechanism, no direct measurement of such incremental costs can be made.

It is clear as explained above that the Company incurred and seeks recovery of costs that fit within the recovery prohibition from the *06-0311 Order*. Therefore, Mr. Schott's assertion that "[i]t would have been a waste of resources to develop a tracking mechanism for such costs where no such costs existed" is completely erroneous. The Company's decision to not track these costs is contrary to the Commission's order, and any adverse consequences from that decision should be borne by the Company and not ratepayers. Staff Ex. 15.0 at 26-27.

Company witness Schott also contends that Staff's adjustment is "against public policy" by "[n]ot allowing recovery of costs to 'come into compliance.'" NS-PGL Ex. JFS-2.0 at 14. Mr. Schott ignores the fact that Staff witness Hathhorn does not recommend disallowance of all costs to "come into compliance." Staff Ex. 15.0 at 23. Rather, she recommends disallowance of costs or expenses solely attributable to the cathodic inspection requirement violations specified in the 06-0311 Order and any incremental costs caused solely by violation of the Act or its implementing regulations discovered by the Commission's consultant. The Commission's Order and Staff's recommendations are legal and proper, as discussed above, and prohibit recovery of costs necessitated by the Company's imprudent non-compliance with pipeline safety regulations.

Furthermore, the Commission's *06-0311 Order* and Staff's proposed adjustment are consistent with public policy. If a utility violates applicable statutes or rules that result in that utility incurring more costs than it would have otherwise incurred without those violations, even if those additional costs are to come into compliance with the applicable requirement, then ratepayers should not bear the additional costs resulting from the utility's violations. To allow otherwise would essentially reward or condone the utility's violations and would not be just and reasonable. Staff Ex. 15.0 at 28.

Calculation of the Adjustment

With respect to the calculation of the adjustment, Staff argues that any lack of precision in Staff's adjustment is solely due to the Company not operating the required internal tracking mechanism to account for the incremental costs. Therefore, it was necessary for Staff's adjustment to be based upon a reasonable estimate. The calculation of Staff's adjustment considered the timing of the work supporting the audit, issuance of the report, implementation of corrective actions (many still in progress), and the timing of the test year. Staff Ex. 1.0 at 34. Staff witness Hathhorn testified and the Company did not dispute her understanding that the distribution expenses would contain most if not all of the costs at issue. Staff's Direct Tdescribed the development of the disallowance to the test year based upon 6 months actual and 6 months forecast of 2008 costs. Much of the work associated with the audit was performed in 2008, and the audit report was issued in August 2008. These facts are uncontested, as Mr. Doerk's testimony confirms that the Company started responding to the Liberty audit findings during the audit period. NS-PGL Ex. ED-3.0 at 8, 9. In addition, as explained above, other actions to address the violations identified in the *06-0311 Order* occurred in 2008. Test year expenses were developed by escalating 2008 expenses 2% for 2009 and another 1.8% for 2010. Staff Ex. 1.0 at 35, fn. 6.

For example, for every $1 million in 2008 charges, $1.038 million is included in the test year, or a cumulative 3.8% increase. Therefore, Staff's 5.0% reduction of costs disallows the 3.8% increase due to inflation of the distribution expenses from 2008 plus 1.2% (5.0% less 3.8%) for corrective actions not allowable for cost recovery under the Stipulation and MOU and *06-0311 Order*, such as the fees from the Liberty Consulting Group and Huron Consulting Group. NS-PGL Ex. SM-2.0 at 4. While Staff is unable to calculate a precise disallowance given the Company's failure to implement a tracking mechanism, it is clear that significant work was performed in 2008 relative to the violations identified in the *06-0311 Order* and discovered by the Commission's consultant. While Staff does not know the exact amount of costs or expenses incurred in this regard, or the exact amount of those costs or expenses representing additional costs that would not have otherwise been incurred, 5% of the cost category including all such costs is a reasonable estimate given the information available to the parties and the Commission. Staff Ex. 15.0 at 30-31.

Further Discussion of the Commission's Standards for Cost Recovery of Prudent and Reasonable Costs.

The Company's interpretation of what is and is not a prudent and reasonable cost sheds light on why no internal tracking mechanism was maintained as ordered by the Commission. Mr. Doerk testified that he was responsible for the Commission directive from the *06-0311 Order* to implement a tracking system. Tr. at 636. At various points in his Surrebuttal Testimony, he testified that costs were not above prudent and reasonable, or prudent and necessary. NS-PGL Ex. ED-3.0 at 7-10. Mr. Doerk testified at hearing that he defines these terms as "costs that would be normally incurred to remain compliant and perform work. It's work that the Company is required to perform." Tr. at 627. It appears the witness did not consider whether any prior violations contributed to the cost incurred as discussed above and in Findings (4) and (11) of the *06-0311 Order*.

Clearly few if any costs could ever be found imprudent or unreasonable notwithstanding a utility's failure to properly maintain its system if the only inquiry is whether the costs were incurred to maintain the system. Under the Company's analysis, as in the *Commonwealth Edison Co.* decision discussed above, a utility could perform its corrosion inspection and maintenance activities in any manner it chose --

timely or untimely, efficiently or inefficiently -- and the Commission would be limited to determining merely whether the amount paid for the work actually performed was reasonable. In analyzing whether costs have been prudently incurred Staff not only reviews the price paid for the goods or services, but also analyzes the reason or reasons for the purchase of the goods or services. If an imprudent or improper action is what caused a cost to be incurred, then that cost is not a prudently incurred cost even if the price paid for the good or service is otherwise reasonable. Here, additional costs resulting from the Company's violations are not prudently incurred costs, and the *06-0311 Order* and Staff's proposed disallowance are proper and consistent with public policy. Staff Ex. 15.0 at 28-29.

Company witness Schott also testified as to his opinion of recoverable costs. It became clear though, at the hearing, that Mr. Schott had no responsibility for implementing the tracking mechanism required of the *06-0311 Order*. His testimony merely presents his interpretation of the *06-0311 Order*, of which he was neither involved nor assigned follow up duties for tracking costs. He had no operational duties for or independent knowledge of the costs at issues; he deferred all such questions to Mr. Doerk. Tr. at 130, 138. Therefore, for the purpose of deciding this issue, his testimony should be given no weight.

Mr. Schott also testified at hearing that he interprets the *06-0311 Order* to not require the Company to track costs solely attributable to Peoples Gas not performing corrosion inspections in a timely manner. Tr. at 136. He further testified that he has no independent knowledge from Mr. Doerk of the nature of the costs at issue. *Id*. at 138. Finally, while first stating he did not agree that costs currently incurred to perform maintenance or repair work that should have been performed in a prior year, and for which there was no reason or justification for delaying such work, may constitute imprudently incurred costs in the current year for ratemaking purposes (*Id*. at 140), he later agreed that notwithstanding the fact that a utility pays a prudent price for some bidder's service it is possible that those costs may not have been prudently incurred. *Id*. at 147.

In summary, Staff believes that its adjustment is sound, reasonable, supported by the facts of the *06-0311 Order* and the instant case, has a sound legal underpinning based on the *Commonwealth Edison Co.* decision and the CILCO order discussed above, is necessary in order to produce just and reasonable rates, and should be adopted by the Commission.

c) Commission Analysis and Conclusion

This issue rests on the Commission's interpretation of the following language included in Findings and Ordering paragraph (11) in the *06-0311 Order*, which states:

> Peoples Gas shall not seek recovery, in any future rate or reconciliation proceeding before the Commission, of costs or expenses solely attributable to Peoples Gas not performing corrosion inspections in a timely manner, as specified in paragraph 4 above or any incremental costs caused solely by violation of the Illinois Gas Pipeline Safety Act or its implementing regulations ("the Act") discovered by the Commission's

> consultant retained pursuant to the Memorandum of Understanding, and which are over and above the prudent and reasonable costs necessary to comply with the Act. Peoples Gas shall operate an internal tracking mechanism to account for any such incremental costs.

06-0311 Order at 8. The Commission finds the language of the Order to support Peoples Gas' position. Two categories of costs were prohibited from recovery: 1) costs solely attributable to untimely corrosion inspections as specified in Findings and Ordering paragraph (4) and 2) incremental costs caused by violation of the Act or the regulations which are over and above the prudent and reasonable costs necessary to comply the Act.

In its brief on exceptions, Staff argues that not only does the *06-0311 Order* support their position, but also that the decision in *Business & Professional People for Public Interest v. Illinois Commerce Comm'n*, 171 Ill. App. 3d 948 (1st Dist. 1988) ("*BPI*") supports their adjustment. Staff asserts that this opinion adopted the principle that if a utility engages in an imprudent act or omission and that imprudence causes an expense to be incurred or causes the overall amount of expense incurred to increase, the resulting expenditure or increased portion thereof is not prudently incurred. *Staff BOE* at 18. There is no similarity between the facts of *BPI* and this proceeding. In *BPI*, the Commission found that it was imprudent for ComEd to have placed the LaSalle 1 nuclear power plant into service in 1982. Because of that imprudent act, the additional $70 million that ComEd paid in replacement power costs was ordered to be refunded to customers. Relevant to the instant proceeding, Peoples Gas' imprudent conduct in 2003 and 2004 was enumerated in the *06-0311 Order* and Peoples Gas was fined $1 million. Thus, the *BPI* decision would have been relevant in the Docket 06-0311 proceeding. The costs at issue here were incurred to comply with Act. Increasing inspectors and completing corrective actions are themselves prudent actions. While *BPI* does not apply, the Commission must now decide whether Findings and Ordering paragraph (11) of the *06-0311 Order* supports Staff's adjustment.

With respect to the first category of costs barred from recovery in Findings and Ordering paragraph (11) of the *06-0311 Order*, Findings and Ordering paragraph (4) of such Order states:

> by the evidence, Peoples Gas was not in compliance with applicable federal and state pipeline safety regulations -- *viz*., 49 CFR §192.13(c) and 49 CFR §192.465(a) and (d), adopted by the Commission at 83 Ill. Admin. Code 590 pursuant to Section 3 of the Illinois Gas Pipeline Safety Act (220 ILCS 20/3) -- respecting cathodic protection inspection and remediation and the requirement to maintain and follow procedures and programs, by being late in conducting corrosion testing on certain service pipes and main segments that were due for inspection before and during 2003 and 2004, and by failing to perform corrective action during 2004 and 2005 at test points on certain service pipes and main segments found to be out of compliance during in 2003 and 2004;

Utilities witness Doerk testified at the hearing that Peoples Gas caught up on corrosion inspections and corrective actions in 2005 and since then has hired additional corrosion control inspectors but no more in number than was prudent and reasonable. Tr. at 640-641. The evidence shows that the catch-up work was completed in 2005 and, therefore, the costs are not included in the test year expenses which are based on actual costs for the first half of 2008. Additional inspectors that have been hired to keep the Company inspections current are not barred from recovery by the *06-0311 Order*. Indeed, it would be contrary to public policy to not allow the Company to recovery its costs for additional safety inspectors.

With respect to the second category of costs, there is no evidence that Peoples Gas has incurred any costs over and above those that are necessary to comply with the Act. The costs that Peoples Gas has expended to comply with the Act and the recommendations of Liberty are not the incremental costs that the *06-0311 Order* sought to bar the company from recovering.

As an extreme example, if a gas line had exploded and ten homes were destroyed because the Company had failed to inspect a line in violation of the Act, then the cost to replace those homes would not be recoverable. If the Company hired 10 extra inspectors as being necessary to ensure its compliance with the Act and as a result no homes exploded, the costs for those inspectors are recoverable.

The Commission's decision in *CILCO 94-0040* further supports our denial of Staff's adjustment. In that docket, the Commission disallowed much of the company's costs for the accelerated replacement of its deteriorating cast iron system. The decision was based on the "overwhelming evidence a systematic course of conduct intended to underreport the number and severity of gas leaks occurring on its Springfield cast iron distribution system . . . this course of conduct led to the existence of a substantial threat to public safety, which necessitated the immediate and accelerated replacement of the majority of the cast iron system and the expenditure of significant sums that would not have been spent but for CILCO's imprudence." *CILCO 94-0040* at 7. In other words, the costs at issue in *CILCO* would not have been incurred "but for the imprudent conduct."

Staff has shown no imprudence here. And Staff's own testimony proves it. A close reading of Staff witness Burk's testimony shows that the Company is seeking to comply with the Act and is incurring only prudent costs to do so. At worst, Mr. Burk's testimony shows Liberty Consulting to have found errors like: the Company's list of contractors was not current and that its marking of buried pipeline for planned excavation was not proper. And, Mr. Burk testified that the practice of the Commission's Pipeline Safety Program is not to pursue citations, but rather to encourage compliance with required safety practices. Staff Ex. 23.0 at 8. According to Mr. Burk, he did not believe it was even necessary to issue a notice of probable violation because Peoples Gas had prepared a proposal to correct the problems. *Id.* In other words, Staff itself admits that such oversights do not rise to the level of *CILCO*. These are not the costs that the Commission intended to disallow. To the extent that our *06-0311 Order* is ambiguous, it must be construed in favor of the Utility. *Adams v. Northern Ill. Gas Co.*, 211 Ill. 2d 32, 69, 809 N.E.2d 1248, 1271 (2004) ("the Act is to be strictly construed in favor of persons sought to be subjected to its operation"). This principle must be applied to the *06-0311 Order* because it is a Commission Order in a citation proceeding where the Commission acted in a judicial capacity and imposed a $1 million civil penalty.

All of this shows that there was no need for the Company to create a tracking mechanism. Mr. Doerk testified that the violations identified in the *06-0311 Order* were corrected in 2005 and it has not been shown that any incremental costs above those necessary comply with the Act have accrued. Moreover, the Utility is shown to be implementing its plan to comply with the Commission's safety regulations. Finally, Staff's position to bar recovery of the Company's costs to comply with safety practices is in conflict with the Pipeline Safety Program Staff's practice and contrary to public policy. We cannot accept Staff's proposal that these costs should have been tracked.

In its Brief on Exceptions, Staff takes issue with the discussion of the Pipeline Safety Program practice. *Staff BOE* at 25. Staff asserts that this decision is somehow contrary to the principle that a penalty proceeding does not bar subsequent action in a proceeding addressing the same conduct. Staff's interpretation, however, does not recognize that the *06-0311 Order* did reduce the Utility's operating expense in this proceeding, i.e., $540,000 have been removed for the Liberty Consulting fees. The fact that the Pipeline Safety Program has not issued a citation supports the Utility's assertion that it has not incurred incremental costs from a violation of the Act.

In the end, Staff's proposed adjustment, 5% of Peoples Gas' entire test year distribution costs, is found to be arbitrary and punitive. For all these reasons, the Commission does not adopt Staff's proposed adjustment.

5. Customer Accounts - Uncollectible Expense Related to Sales Revenues Adjustment

AG-CUB witness Effron's proposed adjustments to increase the Utilities' forecasted sales are not approved, as discussed below. Accordingly, this issue is moot.

6. Customer Service and Information - Advertising Expense

a) Utilities

Staff witness Wilcox proposed an adjustment to reduce operating and maintenance expenses for certain advertising expenses that he concluded were of a promotional, goodwill or institutional nature. The Utilities agreed in part with Mr. Wilcox's adjustment, only taking exception to his disallowance of the costs associated with their Safety, Reliability and Warmth Campaign ("SRW Campaign"). NS-PGL Ex. SM-2.0 at 6-7. The Utilities assert that the disallowance of the "SRW" portion is contrary to the evidence.

Section 9-225 of the PUA states that the Commission cannot consider promotional, political, institutional or good will advertising in a general rate increase requested by an utility. 200 ILCS 5/9-225(2). Staff claims that the SRW costs are the type of promotional adverting costs that the Commission is prohibited from considering. Staff Ex. 6.0 at 6.

According to the Utilities, however, there is nothing in the record that establishes that this advertising campaign is intended to "encourage any person to select or use the service or additional service of a utility or the selection or installation of any appliance or equipment designed to use such utility's service." 220 ILCS 5/9-225(1)(c). The Utilities argue that the SRW campaign informs and educates customers regarding energy conservation and safety measures.

By focusing on the words, Safety, Reliability, and Warmth in the advertising campaign, the Utilities educated customers on the Utilities' services offered and benefits provided to customers. NS-PGL Ex. SM-3.0 Rev. at 5. The energy education advertising in the SRW Campaign focused on three main customer benefits: (1) conserving/managing home natural gas use, (2) billing and payment options, and (3) staying safe and understanding the use and maintenance of the natural gas delivery function. NS-PGL Ex. SM-2.0 at 7. This advertising strategy was used to catch customers' attention particularly with respect to energy efficiency management and customer billing options available to fit their budget and lifestyles. NS-PGL Ex. SM-3.0 Rev. at 5. While Mr. Wilcox wants to dismiss the whole campaign because of the strategy used to catch the customers' attention, the main message of this campaign lets customers know that they have options and control how they manage their bills and energy usage. NS-PGL Ex. SM-3.0 Rev. at 5.

The Utilities assert that Staff's argument is unreasonable. This type of creative communication strategy was used to catch the customers' attention, particularly on energy efficiency management and billing options available to fit their budget and lifestyle needs. Moy Sur., NS-PGL Ex. 3.0 Rev. at 5 . This is especially important in such instances when customers are walking by a poster and not reading a bill insert. While the Utilities still use bill inserts and the corporate website, other forms of media such as radio and billboards are being utilized to promote an energy education message more strongly and reach a wider audience more effectively. *Id*. at 6. Further, creative direction is subjective at every level but the copy in the ads (while not as large as the "SRW words") did directly address these customer needs and benefits. *Id.* at 5. Therefore, the SRW campaign informs and educates customers regarding energy conservation and safety measures pursuant to Sections 9-225(a) and (c) of the Act. 220 ILCS 5/9-225(a), (c).

For all the reasons stated herein, the Utilities maintain that the Commission should reject Staff's argument and allow recovery of the advertising costs associated with the SRW campaign.

a) Staff

While the Companies accept part of Staff's proposed adjustments to advertising expense, they do not accept that part of Staff witness Wilcox's adjustment related to advertising that Staff found to be primarily promotional, goodwill, or institutional in nature. The relevant part of the Act states:

> In any general rate increase requested by any gas or electric utility company under the provisions of this Act, the Commission shall not consider, for the purpose of determining any rate, charge or classification of costs, any direct or indirect expenditures for promotional, political, institutional or goodwill advertising, unless the Commission finds the

> advertising to be in the best interest of the Consumer or authorized as provided pursuant to subsection 3 of this Section.

220 ILCS 5/9-225(2). Section 9-225 of the Act defines goodwill or institutional advertising as:

> … any advertising either on a local or national basis designed primarily to bring the utility's name before the general public in such a way as to improve the image of the utility or to promote controversial issues for the utility or the industry.

220 ILCS 5/9-225(1)(d).

Based on his review of the Companies' advertising material, Staff witness Wilcox proposes adjustments to disallow advertising expenses for the "Safety, Reliability, and Warmth" Campaign ("SRW") because those advertisements were primarily promotional, goodwill, or institutional in nature. Mr. Wilcox specifically explains that the substance of the campaign is promotional even though the words "safety" and "reliability" are used. Staff Ex. 6.0 at 4-6; Schedules 6.3 P and 6.3 N.

According to Staff, the Companies' argument that the promotional and good will elements are the primary means of drawing attention to the advertisements ignores the fact that those attention-getting elements are in fact the primary purpose of the advertisements. Staff notes that in Company-provided photographs of how the advertisements were positioned, the promotional and good will elements are the only ones that are legible. Viewing the advertisements, Staff argues that sprinkling passing references to energy conservation or payment options into the advertisement's fine print does not transform the primary message one receives from the advertisement.

Staff asserts that the Companies' argument that they should recover the costs of the SRW Campaign because they would incur costs for customer education even without the SRW Campaign should be rejected. The evidence demonstrates that the Companies already incur costs for customer education about energy efficiency and billing options outside the SRW Campaign. In fact, those costs are included in the test year and are not the subject of a proposed adjustment. These advertisements are presented in Staff Cross Moy Ex. 22 and Staff Cross Moy Ex. 23. An example of these advertisements for each Company is presented in Attachment 2 to this brief. Even the most cursory comparison of these advertisements with those in the SRW Campaign reveals that they provide much more substantive information than those in the SRW Campaign. The evidence in this proceeding demonstrates that the SRW Campaign is not the primary way the Companies provide information to customers about energy efficiency or payment options. Neither are energy efficiency or payment options the primary message of the SRW Campaign.

The Companies' argument that the SRW Campaign allows them to reach a wider audience with a more powerful message than using bill inserts or the corporate website is troubling to Staff. It is not clear who, besides the customers who receive the bills with the bill inserts, the Companies are trying to reach. Neither of the two mediums utilized in the SRW Campaign – radio ads and posters – specifically target customers of the Utilities. Staff asserts that if it is someone other than the Companies' customers who make up the intended audience for these advertisements, then the Companies' customers should not pay the bill for these advertisements.

Based upon the above arguments Staff urges the Commission to accept all of Staff witness Wilcox's adjustments to advertising expenses.

b) Commission Analysis and Conclusion

The Utilities argument is unconvincing. It is clear that the primary focus of this campaign is promotional and is designed to improve the Utilities' image. The Commission finds these expenditures to be non-recoverable pursuant to Section 9-225 of the Act. The non-promotional information that is included in this campaign is clearly not the focus and would be more appropriately included in bill inserts. We adopt Staff's proposed adjustment.

7. Administrative and General - Injuries and Damages Expenses

a) Utilities

Staff, relying on five year averages of actual claims payments for 2004 to 2008 escalated for 2009 and 2010, proposes to decrease injuries and damages expenses by revised figures of $864,000 as to Peoples Gas and $159,000 as to North Shore. Staff Ex. 17.0 at Scheds. 17.2 N and 17.2 P. Staff's "normalization" proposal, which seeks to substitute Staff's averages for the Utilities' forecasts of injuries and damages expenses, is unwarranted and should not be adopted, for four reasons.

Although the specific numbers have changed and a future test year is proposed here, the Commission is presented with much the same evidentiary record on the subject of injuries and damages expenses as it was in 2007 Peoples Gas and North Shore rate cases, in which it rejected Staff's proposed adjustments.

The only real change on this subject from the prior cases is that the Utilities, in an attempt to narrow the issues, have offered to accept Staff's revised figures for injuries and damages expenses if consistent changes to the reserves for injuries and damages in rate base also are made. Staff has not agreed, however, to those corresponding changes to the reserves.

Staff's proposal, the Utilities argue, should be rejected. As in Peoples Gas' and North Shore's 2007 rate cases, Staff has failed to show that that any "normalization" of injuries and damages expenses was required in the first place. In the instant cases, once again, the figures and averages for the last five years (see the following table) on their face do not support normalization. Rather, they show that the amounts determined by the Utilities' forecasting process are reasonable. NS-PGL Ex. CMG-2.0 at 3-4.

Actual Claims Payments Data*		
	Peoples Gas	North Shore
2004	$6,032,000	$867,000
2005	$3,250,000	$735,000
2006	$5,472,000	$541,000
2007	$4,766,000	$586,000
2008	$6,877,000	$465,000
Five Year Average for 2004 to 2008 Not Escalated for Inflation	$5,279,000	$639,000
Five Year Average for 2004 to 2008 Escalated for Inflation in 2009 and 2010 Only	$5,590,000	$676,000
Utilities' Forecasted Amounts for 2010	$6,454,000	$835,000

*All figures are from Staff Ex. 17.0 at Sched. 17.2 N, at 2., and Sched. 17.2 P, at 2.

Also, Staff's decision to base its proposal on five year averages of actual claims payments for 2004 to 2008 is arbitrary, the Utilities assert, because the selected period lacks any foundation. Staff offered as its sole reason for selecting that data and period that the methodology of using the average of actual claim cash payments over the most recent five years to "normalize" injuries and damages expenses was approved in *In re Central Illinois Light. Co. d/b/a AmerenCILCO, et al.*, Dockets 06-0070, 06-0071, 06-0072 Consol. (Order Nov. 21, 2006) ("*Ameren 2006*"). Staff Ex. 3.0 at 12. That is not correct. In *Ameren 2006*, the Commission approved a methodology that used an average of actual claims payments and accruals over the most recent five years. *Ameren 2006* at 48-49. Staff did not propose that methodology here. Moreover, in the 2007 cases, as quoted above, the Commission expressly recognized that, while it had used a five year period in other cases, use of a five year period "is obviously not a hard and fast rule". *Peoples 2007* at 57.

Further, Staff's approach also is arbitrary because there is no rationale for choosing the five year period over other periods that could have been selected from the same data on which Staff relied. As to Peoples Gas, had Staff chosen the most recent three year period, its methodology still would have yielded a downward adjustment but it would have been $413,000, not $864,000. *See* Staff Ex. 17.0 at Sched. 17.2 P at 2. As to Peoples Gas, had Staff chosen the most recent two year period, its adjustment would have been $290,000. *See id*. As to North Shore, had Staff chosen three or two year periods, the adjustments would have been slightly larger. *See* Staff Ex. 17.0 at Sched.

17.2 N at 2. If Staff had chosen four year periods, its proposed adjustments would have been larger for both utilities. *See id*.

Finally, Staff's proposal, even if it had merit, should not be adopted unless consistent adjustments are made to the Utilities' reserves for injuries and damages in rate base. The Utilities have presented the appropriate related adjustments to the reserves should Staff's proposal be adopted in full, and, in the interests of narrowing the issues, the Utilities remain willing to accept the Staff proposal if the consistent adjustments to the reserves are made. NS-PGL Ex. JH-3.0 at 11-12.

The Utilities have presented the appropriate related adjustments to the reserves should Staff's proposal be adopted in full, and, in the interests of narrowing the issues, the Utilities remain willing to accept the Staff proposal if the consistent adjustments to the reserves are made. *Id*. Staff's attempted rationalization of its refusal to agree to the corresponding adjustments is illogical and lacks any credibility. Staff offers the contrived theory that, because the Utilities' injuries and damages reserves figures are forecasted but Staff has substituted a normalization of the injuries and damages expenses based on historical data, it is somehow appropriate to reject the expenses part of the forecast while refusing to adjust the reserves part of the forecast. The Utilities argue that is arbitrary and results-driven. Indeed, Staff says what matters for the reserves is the estimate of future payments, *id*., but Staff completely overlooks that its proposed adjustments do nothing other than use historical data to change the forecast of future payments.

Accordingly, the Commission should either (1) reject the Staff proposal and make no adjustments to the reserves or, alternatively, (2) adopt the Staff proposal and make the consistent adjustments to the reserves.

b) Staff

The Companies accepted Staff witness Ostrander's proposed adjustments to injuries and damages expense contingent upon what they allege are consistent adjustments with respect to the injuries and damages reserves in rate base. NS-PGL Ex. SM-3.0 at 4. Staff disagrees that corresponding adjustments should be made to the injuries and damages reserves in rate base.

The Companies believe that there is a direct correlation between the amount of injuries and damages expense and the amount of the injuries and damages reserve amount which would warrant that any adjustment made to expense should also be made to the reserve. The Companies direct correlation argument is based on the bookkeeping entries that are made when an expense is accrued or adjusted and when a claim payment is made. NS-PGL Ex. JH-3.0 at 12. Staff agrees in theory that the Companies are making the proper bookkeeping entries to record the economic transactions associated with injuries and damages. However, for purposes of determining a revenue requirement, Staff does not agree that there is a direct correlation between the injuries and damages reserve and the expense amounts. Nor is there a need for a rate base adjustment due to the test year normalized operating expense adjustments proposed by Mr. Ostrander. While the 2010 expense accrual component of the injuries and damages reserve represents the Companies' cumulative estimate of what payments will be made in the future for incurred injuries and damages claims as of December 31, 2010, the normalized level of injuries and damages operating expense is based on actual historical claim payments. Staff Ex. 3.0 at 12. As such, Mr. Ostrander's proposed adjustments to reflect a normal level of annual operating expense or period cost are based on historical payments and have no direct corresponding impact on the estimate of the test year balance sheet liability or reserve for future payments. Thus, it would be inappropriate to adjust the Companies' injuries and damages reserve in rate base due to a rate making adjustment to normalize the injuries and damages operating expense in the revenue requirement.

The Companies assert that the injuries and damages amounts initially proposed in the 2010 test year operating expenses are reasonable. NS-PGL Gas Ex. CMG-2.0 at 3-4. Yet, for the most recent five year period, 2004 – 2008, the actual payments for injuries and damages claims in 4 of the 5 years were less than the amount the Companies accrued in the 2010 test year. Staff Ex. 17.0, Schedules 17.2 N and P at 2. A normalized operating expense amount should reflect the expected annual recurring level that the Companies expect to pay, apart from unusual conditions. Historical payments (experience) are a good standard against which to evaluate an expected recurring level of expense. Since the 2010 expense accruals are greater than historical experience, the Companies' injuries and damages expense accruals should be decreased to reflect a normalized level of expense in the Companies' 2010 test year operating expenses.

The Companies take issue with Staff's use of a five year period of average actual claims paid, arguing that other periods could have been selected from the data that Staff relied upon. However, the Companies' use of 2 year, 3 year, and 4 year data demonstrate that the resultant adjustments do not drastically vary from Staff's proposed normalization adjustments based on the use of a five year period of actual claims paid. NS-PGL IB, at 71. Therefore, choosing different time periods for normalization does not skew the results as the Commission found was the case in the Companies prior rate case. NS-PGL IB, at 69. The adjustments recommended by Staff to reflect a normalized level of injuries and damages operating expense for the 2010 test year are appropriate and should be adopted by the Commission.

c) Commission Analysis and Conclusion

In the Utilities' last rate case, the Commission found that:

> We see from the record that depending on the time periods selected for normalizing, the results will either be fairly representative or skewed. While this Commission has accepted 5-year averaging in other cases, this is obviously not a hard and fast rule. It is always necessary, when gathering any periods of data, to further apply sound and reasoned judgment. Here, we are not persuaded by the correctness of using 5 years of data for reasons that one of these years, i.e., 2002, is clearly and unmistakably different from the others. Further, we perceive that something is inherently wrong in the selection when the results change so drastically when either 3 or 4 year data is considered.

Peoples 2007 at 57. Similar to the last case, depending on which years and how many years are chosen to include in the average, the result is very different. For the same reasons expressed by the Commission in the Utilities' last rate case, we decline to use the normalizing proposed by Staff.

8. Revenues - Sales Revenues Adjustment

a) Utilities

AG-CUB witness Effron proposes to increase the forecasted sales revenues of North Shore by $550,000 and of Peoples Gas by $4,441,000. AG/CUB/City Ex. 1.0 at 13-15; AG-CUB Ex. 4.0 at 6-8; AG-CUB Ex. 4.1 at Scheds. C and C-1 Corr.; AG-CUB Ex. 4.2 at Scheds. C and C-1 Corr. Those adjustments would lead to reduced revenues being collected under the new rates. *E.g.,* NS-PGL Ex. DWC-3.0 at 1, 2-3. The proposal lacks merit and should not be adopted, for five reasons.

According to the Utilities, there is no sound reason to reject the Utilities' sales forecasts and substitute Mr. Effron's proposal. First, the Utilities' sales forecasts are the product of detailed, thorough forecasting methodologies conducted by, and that were supported in testimony by, experienced forecasters. *See* NS Ex. BMM-1.0, and PGL Ex. BMM-1.0; NS Ex. DWC-1.0 and PGL Ex. DWC-1.0. In contrast, the Utilities state that Mr. Effron has no significant training or experience as a sales forecaster. *See* AG/CUB/City Ex. 1.0 at 1-2.

Also, Mr. Effron's proposal improperly selects one factor out of the sales models to update and ignores all other factors, including the "Efficiency Improvements" group of variables, which includes the state of the economy, and which is more powerful than the price factor and drives down usage per customer. NS-PGL Ex. DWC-2.0 at 1, 2-5; NS-PGL Ex. DWC-3.0 at 1-2. Because of timing, the economic downturn was not captured in the Utilities' sales forecasts used in their filings. Updating all of the variables, not just a single results-driven factor, likely would result in lower sales forecasts. *Id*. at 1; *see also* Tr. at 406.

Further, Mr. Effron overlooks that his proposal, if adopted, would be offset by necessary decreases in the test year revenues the Utilities forecast under their decoupling riders, reducing his adjustments to $28,000 as to North Shore and $489,000 as to Peoples Gas. NS-PGL Ex. VG-3.0 at 2, 3, 21-22; NS-PGL Exs. VG-3.2N and VG-3.2P.

Finally, Mr. Effron's proposal also overlooks that, if adopted, it would require an increase in the Utilities' uncollectibles expense. NS-PGL Ex. CMG-3.0 at 7.

Staff witness Harden offered rebuttal testimony supporting the concept of Mr. Effron's proposal, although not his numbers, but her testimony does not provide any valid grounds for approving the proposal. She also presented no additional grounds for the proposal, and also overlooked the offsets referenced above. NS-PGL Ex. DWC-3.0 at 2-3.

Accordingly, the Utilities argue that the Commission should reject Mr. Effron's proposal.

b) AG

AG/CUB/City witness Effron proposed adjustments to test year sales and revenues forecasts related to their sensitivity to the projected cost of gas. As noted by Mr. Effron, the current forecast of the 2010 price of gas is significantly lower than the projected prices at the time the sales forecasts were originally prepared. AG/CUB/City Ex. 1.0 at 14. Therefore, the sales forecasts should be modified to reflect the current forecast of 2010 gas prices.

In response to Data Requests PGL AG 3.48 and NS AG 3.90, the Companies provided revised forecasts of 2010 sales assuming a NYMEX gas price of $6.52 per MMBtu, which was the alternative price referenced in Part 285 Schedule G-5. *Id.* at 14. In response to Staff Data Requests PGL ENG 3.02 and NS ENG 3.02, the Companies provided an updated forecast for the 2010 price of gas of $6.06 per MMBtu, including the Chicago basis spread. *Id.* Based on that data, Mr. Effron extrapolated the sales adjustments in these data request responses to calculate the effect on 2010 sales of incorporating a gas price of $6.06 per MMBtu. *Id.*

The results of his calculations, shown on his respective Schedules C-1, increased the forecasted PGL Rate 1 sales by 15,671,000 therms and Rate 2 sales by 9,650,000 therms. The increase in therm sales to these rate classes resulted in an increase to test year base revenues under present rates of $4,344,000. *Id.* at 14-15. For North Shore, the modification increased the forecasted NS Rate 1 sales by 2,911,000 therms and Rate 2 sales by 3,373,000 therms. The increase in therm sales to these rate classes resulted in an increase to test year base revenues under present rates of $559,000. *Id.* Mr. Effron explained that these increases to therm sales should be reflected in both the determination of pro forma operating income under present rates and the calculation of rates necessary to produce the Companies' calculated revenue requirements. *Id.*

In his rebuttal filing, Mr. Effron updated his sales adjustment to incorporate more recent estimates of the test year price of gas. Those updated adjustments can be found in AG/CUB/City Ex. 4.1, Schedule C-1 (NS) and AG/CUB/City Ex. 4.2, Schedule C-1 (PGL), attached to Mr. Effron's rebuttal testimony. This modification increases Peoples' test year revenues by $15.553 million and North Shore's test year revenues by $2.839 million. AG/CUB/City Ex. 4.0 at 8.

In response to Utilities witness Clabots' criticism that these adjustments are "one-sided," Mr. Effron noted that Mr. Clabots cites other possible changes in variables affecting sales since the Companies' forecasts were originally prepared, but does not quantify the potential effect of such changes on test year sales or even present evidence that such changes in these other variables have actually taken place. AG/CUB/City Ex. 4.0 at 7.

For example, he noted that Mr. Clabots cites efficiency and the trend in large volume customer consumption as other variables that would affect sales. *Id.* However, the Companies already took these variables into account in their forecasts of test year sales. *Id.* Mr. Effron pointed out that Mr. Clabots failed to present any data showing that the assumptions used in the original forecasts of those variables are no longer valid nor any quantification of what the effects of modifying those assumptions would be. *Id.*

Mr. Clabots presented no evidence that Mr. Effron's proposed adjustments to test year sales to reflect lower gas prices are incorrectly quantified or otherwise erroneous. Mr. Clabots' criticism appears to focus on the notion that there might be other adjustments that could possibly offset them. This argument is specious, however. As noted by Mr. Effron, each adjustment should stand or fall on its own merits. If a proposed adjustment is not well founded or erroneous, it should be rejected. If a proposed adjustment is sound on its own merits, then it should not be rejected because it is possible that there could be other related adjustments that go in the opposite direction.

For all of these reasons, the Commission should adopt Mr. Effron's proposed adjustment to both the determination of pro forma operating income under present rates and the calculation of rates necessary to produce the Companies' calculated revenue requirements, as discussed above.

With respect to the Utilities' argument that uncollectible expense will need to be increased as a result of the adjustment, the AG states that this is factually incorrect. The increase to uncollectible accounts expense associated with the sales increase was explicitly recognized. Schedule C-2, Note 5.

As noted by the AG, the current forecast of the 2010 price of gas is significantly lower than the projected prices at the time the sales forecasts were originally prepared. AG/CUB/City Ex. 1.0 at 14. Therefore, the sales forecasts should be modified to reflect the current forecast of 2010 gas prices. The Companies' assertion that other variables in the forecast need to be adjusted rings hollow when those adjustments are not quantified. To ignore the effect of the significant change in the price of gas for purposes of setting the test year sales forecast would result in ratepayers paying excessive rates. It should be noted, too, that Staff witness Harden supported the concept of updating the forecast based on this variable. Staff Ex. 24.0 at 18.

The AG recommends that Commission adopt Mr. Effron's adjustment.

c) Staff

Staff addressed this issue in its briefs in the cost of service section.

d) Commission Analysis and Conclusion

Mr. Effron's proposal improperly selects one factor out of the sales models to update and ignores all other factors. The Commission notes evidence presented by the Utilities that Mr. Effron did not update the "Efficiency Improvements" group of variables, which includes the state of the economy and is more powerful than the price factor and drives down usage per customer. NS-PGL Ex. DWC-2.0 at 1, 2-5; NS-PGL Ex. DWC-3.0 at 1-2. Because of timing, the economic downturn was not captured in the Utilities' sales forecasts used in their filings. Updating all of the variables, not just a single results-driven factor, would perhaps result in lower sales forecasts. Although it would probably have been helpful for the Utilities to have updated everything based on the drop in the price of gas, that evidence is not before us. The record as it stands does not support the AG's adjustment.

D. Depreciation (Uncontested Except for Derivative Adjustments from Contested Adjustments)

There are no contested issues relating to depreciation expense. The only contested aspects of the expense are the derivative impacts of contested plant adjustments.

E. Taxes Other Than Income Taxes (Payroll and Invested Capital Taxes) (Uncontested Except for Derivative Adjustments from Contested Adjustments)

There are no contested issues relating to taxes other than income taxes. The only contested aspects of these taxes are the derivative impacts of certain contested adjustments.

F. Total Operating Expenses

Based on the operating expense statement as originally proposed by the Utilities and the adjustments to operating revenues and expenses as summarized above, the total operating expenses for Peoples Gas and North Shore approved for purposes of this proceeding may be summarized as follows:

Approved Operating Statements (in thousands)

	Peoples Gas	North Shore Gas
Base Rate Revenues	$ 507,982	$ 76,990
PGA Revenues	-	-
Coal Tar Revenues	-	-
Other Revenues	22,681	2,077
Total Operating Revenue	530,663	79,067
Uncollectible Expense	29,916	1,653
Cost of Gas	-	-
Other Production	-	310
Distribution	98,275	10,394
Customer Accounts	33,735	7,521
Customer Service and Informational Services	4,795	846
Sales	-	-
Administrative and General	111,524	24,144
Depreciation and Amortization	81,443	9,428
Storage	10,128	-
Transmission	2,703	425
Taxes Other than Income	20,767	3,204
Total Operating Expense Before Income Taxes	393,286	57,925
State Income Tax	7,200	607
Federal Income Tax	38,521	1,050
Deferred Taxes and ITCs Net	(5,059)	4,486
Total Operating Expenses	433,948	64,068
NET OPERATING INCOME	$ 96,715	$ 14,999

VI. Rate of Return

A. Overview

The legal standards governing a public utility's entitlement to a fair and reasonable return on its investment are well established. These classic and enduring pronouncements were set out by the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Comm'n of the State of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*")) and *Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) ("*Hope*") cases. A public utility has a constitutional right to a return that is "reasonably sufficient to assure confidence in the financial soundness of the utility and [is] adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." *Bluefield,* 262 U.S. at 693. The authorized return on equity "should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Hope,* 320 U.S. at 603.

Illinois law is consistent with these principles. The Commission "is charged by the legislature with setting rates which are '*just and reasonable'* not only to the ratepayers but to the utility and its stockholders." *BPI II,* 146 Ill. 2d at 208-209 (citing 220 ILCS 5/9-201); *see also* 220 ILCS 5/9-101. And, this Commission "fully embraces the principles set forth" in the *Bluefield* and *Hope* cases. *In re Consumers Ill. Water Co.,* Order at 41, Docket 03-0403 (April 13, 2004).

B. Capital Structure

1. North Shore and Peoples Gas Position

Utilities witness Mr. Johnson testifies that a strong capital structure benefits the Utilities' customers by maintaining ready access to capital in all market conditions, maintaining strong credit ratings and reducing their cost of debt. Accordingly, the Utilities each proposed a capital structure of 56% common equity and 44% long-term debt. This capital structure is consistent with their currently authorized capital structures. *Peoples 2007* at 73. It also approximates the Utilities' actual fiscal 2007 year-end capital structures, as well as their actual average structures over the past several years. The Utilities propose no changes to their traditional practice of using short-term debt only to finance seasonal cash needs, particularly for purchased gas costs and short-term construction work in progress, and not as a permanent source of financing rate base investments.

The Utilities state that their proposed exclusion of short-term debt from their capital structures is consistent with this Commission's regulation of them over the past 20 years, and their planned use of short-term debt is consistent with their past practice that served as a basis for the Commission's decisions over that period. They emphasize that they issue short-debt debt only temporarily to manage short-term cash flows at certain times of the year, typically at year-end when higher winter revenues have not been collected and seasonal cash requirements are at their highest, and in the late summer months when revenues are at their lowest. As such, Utilities argue, they have satisfied the showing delineated in our decision in *Northern Illinois Gas Company d/b/a Nicor Gas Company,* Docket 04-0779 (Sept. 30, 2005). The Utilities also note that they are forecast to have no short-term debt balance for most of the test year, and this distinguishes these cases from our more recent decision on rehearing in *Northern Illinois Gas Company d/b/a Nicor Gas Company*, Docket 08-0363, *Order on Rehearing Oct. 7, 2009*.

The Utilities reject each of Staff's arguments, adopted by CUB/City, for including a short-term debt component in their capital structures. First, this Commission has in the past rejected claims that differences between rate base and capital structure demonstrate that short-term debt is being used to finance rate base. Indeed, we have in past cases recognized that capitalization and rate base are not measured in the same way and cannot be directly compared. *Re Ameren Illinois Utilities*, Order at 67, Docket 02-0798 *et al.* (consol.) (Oct. 22, 2003). Moreover, in these rate cases, the differences do not support Staff's theory. Peoples Gas' permanent capital exceeds rate base and North Shore's rate base exceeds its permanent capital by only about $11 million. *Id.* at 9. In addition, the Utilities' forecasted average net cash balances exceed their short-term debt balances, which indicates that cash is the source of funding for any differences between rate base and capital structure. NS-PGL Ex. BAJ-2.0 Rev. at 9-10. The Utilities also showed that there is simply no relationship between cash working capital and net working capital. NS-PGL Ex. BAJ-2.0 Rev. at 11-12. Even if there were, the Utilities point out that they included cash working capital in their rate bases in their last rate cases and the Commission, with Staff support, approved capital structures with no short-term debt component. PGL Ex. JH-1.0 at 34; NS Ex. JH-1.0 at 30.

2. Staff's Position

According to Staff, Peoples Gas has an actual average 2010 capital structure comprising $532,238,953 long-term debt or 40.33%, $19,113,513 short-term debt or 1.45%, and $768,405,875 common equity or 58.22%. Staff notes that the Company proposed a hypothetical capital structure comprising 44% long-term debt and 56% equity.

Staff observes that the Company's proposed capital structure, which excludes short-term debt, produces a lower overall rate of return for the Company than its forecasted average 2010 capital structure, which includes short-term debt. Therefore, and to reduce issues in this case, Staff accepts for purposes of this proceeding Peoples Gas' proposed hypothetical capital structure of 0% short-term debt, 44% long-term debt and 56% common equity even though Peoples Gas clearly uses short-tem debt to finance rate base. Although Staff is not contesting the Peoples Gas' proposed capital structure, it requests the Commission reflect its reasons for doing so.

According to Staff, North Shore has an actual average 2010 capital structure comprising $72,476,045 long-term debt or 41.44%, $6,843,865 short-term debt or 3.91%, and $95,578,042 common equity or 54.65%. Staff notes that the Company proposed a hypothetical capital structure comprising 44% long-term debt and 56% equity.

Staff notes that the Company's proposed hypothetical, imputed capital structure, which excludes short-term debt, produces an overall rate of return of 7.90%. The Company's forecasted average 2010 capital structure, which includes short-term debt, produces an overall rate of return of 7.85%. Staff points out that the overall rates of return produced by both capital structures are very similar. Therefore, and to reduce issues in this case, Staff accepts for purposes of this proceeding North Shore's proposed hypothetical capital structure of 0% short-term debt, 44% long-term debt and 56% common equity even though North Shore clearly uses short-tem debt to finance rate base. Although Staff is not contesting the North Shore's proposed capital structure, it requests that the Order reflect Staff's reason for doing so.

3. CUB/City Position

CUB/City notes that Staff and the Companies have now adopted for ratemaking purposes the Utilities proposed 44-56% hypothetical debt-equity ratio, with the cost of debt represented by the Companies' individual costs of long-term debt. CUB/City further notes that while Staff adopts the Companies' position, it does not abandon its conclusion that each Company "clearly uses short-tem debt to finance rate base." CUB/City observes that the basis for Staff's decision is that there is little difference in overall returns resulting from more precise calculations that include short-term debt and because the Companies' proposed hypothetical capital structure yields a small comparative benefit for ratepayers.

In CUB/City's view, the Companies' and Staff's position should be rejected. These parties point out that the Companies do not dispute the existence of or their plans to use short-term debt in the test year. Nor do they deny that at least one of their (revised) rate bases will exceed permanent financing (equity plus long term debt), even if total permanent financing covers the combined rate bases total. The Companies simply deny that short-term debt is used to finance rate base, asserting that cash covers any shortfall and that their short-term debt proceeds are used only to cover operational expenses, and no capital costs, with any shortfall for capital needs covered by cash.

According to CUB/City, the Companies rely on two inapposite Commission decisions from the 1980s. Relying on a 1987 Commission decision, CUB/City observe the Companies to contend that the excess of their capital needs over available permanent financing does not indicate the use of short-term debt to fill the gap. CUB/City assert that the Utilities' argument ignores the Commission's later superseding disposition of this issue. CUB/City state that the later ruling is both directly on point and more consistent with the burden of proof the PUA imposes on utilities in rate cases. 220 ILCS 5/9-201(c). In particular, CUB/City cite the Commission's Order in a recent Ameren rate case where it stated that "[d]ue to the fungible nature of capital, it is generally assumed that all assets, including assets in rate base, are financed in proportion to total capital." *Re Ameren Illinois Utilities*, Order at 67, Docket 02-0798 *et al.* (consol.).

In the view of CUB/City, the Commission is obliged to use the best available data in setting cost-based rates. Here, the Commission should find that the Companies use their short-term debt to finance rate base. CUB/City witness Christopher Thomas testified "The Companies have consistently relied on short-term debt as a source of funds and they forecast a continued need to do so." CUB/City Ex. 2.0 (Rev.) at 54. Accordingly, CUB/City conclude that those funds should be a discrete part of the capital structure used to set rates.

4. Commission Analysis and Conclusion

This Commission has essentially treated short term debt on a case by case basis. We continue to do so today and focus on the facts and circumstances of record at hand.

To reduce issues in this case, Staff did not contest the Utilities' proposed capital structure which contains no short-term debt component because it will result in a lower revenue requirement for Peoples Gas and make little difference in North Shore revenue requirements in comparison to what Staff contends is those Companies' actual capital structures with short-term debt. In short, Staff sees a small benefit. CUB/City claim that the utilities do not deny that the existence of their plans for using short-term debt in the test year, and, they claim the Companies use their short-term debt to finance rate base. The Utilities assert that they issue short-term debt only temporarily to manage short-term cash flows at certain times, typically at year-end when higher winter revenues have not been collected and season cash requirement are at their highest and in late summer months when revenues are at their lowest. Altogether, the stronger showing in this case comes from the Utilities.

It was claimed that the Utilities must be using short-term debt to finance rate base because their estimated rate bases exceed the long-term capital in their proposed capital structures. This argument proceeds on the notion that if a utility's rate base exceeds its long-term capital, it is using short-term debt to finance rate base. However, this Commission does not necessarily accept this proposition as a foregone conclusion. Further, particular to this case, we are shown that PGL's capitalization is larger than its rate base and North Shore's capitalization is about the same size as its rate base.

Just as significant is that only two years ago, the Commission approved the same capital structure that the Utilities propose in this case; the record shows no difference between how the Utilities use short term debt today and how they used it at that time.

For these reasons, the Commission finds a capital structure of 0% short-term debt, 44% long-term debt, and 56% common equity to be appropriate for both Peoples Gas and North Shore.

C. Cost of Long-Term Debt

1. North Shore (Uncontested)

a) The Record

North Shore accepts the Staff-adjusted average cost of long-term debt in 2010 for ratemaking purposes of 5.48%. ; NS-PGL Ex. BAJ-2.1N.

b) Commission Analysis and Conclusion

The Commission observes the North Shore figure to be uncontested. The Commission finds 5.48% to be acceptable in these premises.

2. Peoples Gas

a) Company's Position

Peoples Gas originally proposed a long-term debt cost of 5.96%. The Company later accepted Staff's adjustments to its long-term taxable debt, but it proposes two adjustments to the Staff-adjusted cost of its insured tax-exempt long-term debt. Staff accepts Peoples Gas' request that the adjustment to the insurance premium cost associated with that debt be halved to reflect the Utility's split credit rating.

The remaining issue, the Company informs, involves Staff's reduction of the cost of Peoples Gas' Series OO auction rate bonds to less than 1%. This rate is based on the formula rate of 175% of the London Interbank Offered Rate ("LIBOR") when auctions for these securities fail. With LIBOR near zero, the current rate on these bonds is less than 1%. Peoples Gas acknowledges that the current cost of its Series OO bonds is very low and facially attractive, but the Utility warns that the formula rate could cause sharp increases in this cost as interest rates rise in the future. Moreover, because these bonds are held by some of the Utility's core credit banks, forcing them to earn such low returns may be detrimental to the Utility and its customers in the long-run. For these reasons, Peoples Gas concludes that these bonds are no longer a viable form of long-term financing and proposes to refinance or remarket them in 2010. As such, Peoples Gas proposes that its rates assume a 1% cost for this debt for half the year and a fixed rate debt cost of 7.16% for the remainder of the year. The 7.16% rate is based on indicative rates the Utility received from the market.

b) Staff's Position

The Company and Staff agree that an adjustment to Peoples Gas' cost of long-term debt is necessary to reflect its stand alone financial strength. According to Staff, the actual cost of long-term debt for Peoples Gas reflects the Standard & Poor's ("S&P") and Moody's credit ratings for the Company, which non-utility affiliates have affected. S&P downgraded the credit ratings of the Company to A- from AA- on September 26, 2002, and Moody's downgraded the credit ratings of the Company to Aa3 from Aa2 on September 23, 2002. Staff witness Michael McNally testifies that affiliation with unregulated or non-utility companies adversely affected Peoples Gas' credit ratings. In determining a reasonable rate of return for establishing rates, Staff points out, Section 9-230 of the PUA prohibits the inclusion of any incremental risk or increased cost of capital, which is the direct or indirect result of the public utility's affiliation with unregulated or non-utility companies. Since all but one of the outstanding debt series of Peoples Gas were issued after the downgrades occurred, and those downgrades were due to the utilities' affiliation with unregulated companies, Staff believes the costs associated with such issues need to be adjusted to eliminate the increased cost associated with the lower rating. From an analysis of concurrent bond yield spreads, Staff witness Kight-Garlisch lowered the interest rate on the Series NN bonds to 4.57% from 4.625%, the Series SS bonds to 6.75% from 7%, the Series MM bonds to 3.94% from 4.00%, the Series TT bonds 30 basis points to 7.70% from 8.0%, the New Issue 2009 bonds to 7.43% from 7.75% and New Issue 2010 bonds to 7.58% from 7.9%.

The Series KK, LL, OO, QQ and RR bonds of Peoples Gas, Staff notes, were issued as insured tax-exempt bonds to the Illinois Development Finance Authority ("IDFA"). Staff explains that the repayment of the principal and interest on the bonds issued to the IDFA is secured by an insurance policy, purchased by Peoples Gas. As a consequence of that insurance, the IDFA bonds were rated AAA at the time of issuance. According to Staff, all five bond series were issued after the ratings downgrades and therefore reflect the increased risk of the unregulated affiliates. Had Peoples Gas' credit ratings not been downgraded, Staff maintains, the insurance premium would have been lower since Peoples Gas would have posed less credit risk to the insurers of the bonds. Therefore, Ms. Kight-Garlisch reduces the recoverable insurance fees for each of the issues and the associated annual amortization of those fees to reflect the lower credit risk had Peoples Gas' rating remained Aa2/AA-.

Ms. Kight-Garlisch begins with the total amount of the insurance fee paid by Peoples Gas on each tax-exempt series and subtracts amortization through December 31, 2010. She then reduces the December 31, 2010 unamortized debt expense balance by half, which thereby reduced the amortization of debt expense by the amount attributed to that portion of the insurance fee. Although she does not agree with the manner in which Company witness Johnson calculated the insurance cost adjustment, for purposes of reducing issues in this case, Ms. Kight-Garlisch adjusts her cost of debt to reflect half the adjustment she proposed in her direct testimony. The revised cost of long-term debt for Peoples Gas is 5.28%.

Staff recognizes that there remains a disagreement between it and the Company on the interest rate to be applied to the Series OO auction rate bonds. These Series OO auction rate bonds were issued as insured tax-exempt bonds to the IDFA. When Staff witness Kight-Garlisch filed her direct testimony she adjusted the interest rate on the Series OO bonds to reflect the most recently available auction rate of .998% set at the April 29, 2009 auction and the auction rate she used was provided to her by the Company. Staff states that the April 29th auction, along with every other auction since March 2008, was a failed auction. Staff states that, when there is a failed auction, according to the terms of the bonds, Peoples Gas must pay the default rate which is 175% of LIBOR capped at 14%. Since February 2009, Staff notes, the LIBOR has been less than 1% (0.329%, 0.470%, 0.520%, 0.418% and 0.319% on the following dates in 2009: 1/14, 2/18, 3/25, 4/29, and 6/3 respectively). While the Company claims Ms. Kight-Garlisch's rate is excessive, Staff contends that this rate represents the actual current cost incurred by the Company on the series OO bonds. While the Company argues that it could refinance these bonds with a fixed rate of 7.16%, Staff believes that argument is unsound. Even as interest rates have fallen and investors in these bonds may not be earning a rate they originally desired, for Staff that is not a valid reason for the Company to bail out those investors by remarketing or refinancing the debt at a greater cost to the Company. Rather than trying to dump these low cost bonds, the Company should be embracing them since they result in a lower cost of debt for the Company. The Company's argument that they want to lock in a fixed rate due to fluctuating interest rates ignores the fact that back in 2003 when the Company issued the OO bonds that same risk existed yet the Company chose to issue these auction rate bonds. Staff notes Company witness Johnson to argue that an average rate of 4.08%

should be used for the bonds (1% for 6 months as proposed by Staff and 7.16% as proposed by the Company). Staff disagrees on account that trying to accurately forecast interest rates is problematic. The record shows that accuracy diminishes as the forecast period lengthens. In addition, while current rates may be low when compared to a historical basis, there is still room for rates to move even lower. For all these reasons, Staff argues that its recommendation to continue the use of actual spot interest rates rather than forecasted interest rates to estimate the Company's cost of debt, should be adopted.

c) Commission Analysis and Conclusion

The Commission finds that Staff's use of current rates on the Company's Series OO debt is superior to the Company's proposed use of forecasted interest rates. Therefore, we adopt a 0.998% interest rate for the Series OO debt and conclude that Peoples Gas' cost of long-term debt is 5.28% for the average year 2010.

D. Cost of Common Equity (PGL and NS - combined)

Because the Utilities' common stock is not publicly traded, their cost of equity must be estimated using capital market and financial data relied on by investors to assess the relative risk of other natural gas utilities.

Three parties present analyses of the Companies' costs of common equity: PGL/NS, CUB/City, and Staff. The Companies estimate both North Shore's and Peoples Gas's cost of common equity to be 11.87%, regardless of whether any of the Companies' proposed riders are adopted. CUB/City estimates both North Shore's and Peoples Gas's cost of common equity to be 8.58%, assuming no riders are adopted. If Riders VBA and UEA and stabilizing changes in rate design are adopted, CUB/City recommends a 32.5 basis point downward adjustment, for a cost of equity of 8.255%. Staff estimates North Shore's cost of common equity to be 9.79% and Peoples Gas's cost of common equity to be 9.69%, both of which include a 10 basis point adjustment for Rider VBA. Staff recommends further adjustments to North Shore's and Peoples Gas's costs of common equity of 20 basis points and 65 basis points, respectively, for reason of Rider UEA. In addition, Staff recommends a rate of return on the common equity factor for Rider ICR of 8.06%, which represents a 163 basis point adjustment from the base cost of equity, should the Commission approve Rider ICR for Peoples Gas in this proceeding.

1. Utilities' Position

Utilities witness Moul presents three "market" measures of the Utilities' return on equity ("ROE") based on a proxy group of natural gas utilities with an overall risk profile similar to the Utilities. Mr. Moul applied the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM") and the Risk Premium model. The initial and updated results presented by Mr. Moul are as follows:

Model	February	July
DCF	10.58%	11.41%
CAPM	12.51%	11.80%
Risk Premium	12.50%	12.25%

Assigning a 25% weight to his DCF results and 75% to his CAPM and Risk Premium results, Mr. Moul's updated ROE result of each Utility is 11.87%.

The Utilities assert that Mr. Moul's recommended ROE is supported by the "general context" in which the Commission must determine their cost of equity. The Utilities urge the Commission to consider information beyond the traditional financial models, because each of the models relies on different assumptions and has its own limitations.

To this end, Utilities witness Fetter, former chairperson of the Michigan Public Service Commission, identifies several considerations for the Commission. In particular, Mr. Fetter warns that a reduction in the Utilities' authorized ROEs from their current levels of 10.19% (Peoples Gas) and 9.99% (North Shore) in the midst of "the most challenging economic environment during the past 80 years" would be viewed by the financial markets as "a major setback" and could lead to further downgrades of the Utilities' credit ratings, which are currently split between the "A" and "BBB" levels. Such downgrades could be particularly harmful, given the extraordinary high capital costs currently borne by BBB-rated utilities compared to their A-rated counterparts. Mr. Fetter finds recent returns authorized by this and other commissions in the mid-10% range, and suggests that the Commission take these into account as a point of comparison to the positions that Staff and the parties take in this proceeding.

In particular, Mr. Fetter notes that the ROEs proposed by Staff and CUB/City are at the low end of the range of returns recently issued by other state commissions and are below any ROE ordered by this Commission for a natural gas utility since at least 1972. As a former regulator, Mr. Fetter suggests that the Commission consider results from other jurisdictions because they affect investor decisions and provide the Commission "an awareness of trends in the markets" as it evaluates the results from its "tried and true" financial market models.

The Utilities assert that Commission precedent supports the consideration of general market conditions and trends in addition to the results of the financial market models because these considerations are central to investor expectations. The Utilities point to past Commission decisions that the cost of equity must be determined from the perspective of the investor and that judgment must be applied in evaluating the results of the financial market models.

The Utilities argue that all of these considerations support an increase of the Utilities' cost of equity to the 11.87% level calculated by Mr. Moul.

The Companies' DCF Analysis

The DCF model expresses the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return, which for common stock is the dividend yield plus future price growth. Mr. Moul estimated the dividend yield for the Gas Group by calculating its six-month average dividend yield, adjusting that average by three generally accepted methods to reflect investors' expected cash flows, and the averaging the three adjusted values. For the investor-expected growth rate, Mr. Moul evaluates an array of historical and forecast growth data from sources that are publicly available to, and relied upon by, investors and analysts. He focuses on forecasts of earnings per share growth because empirical evidence supports it and because that they are most relevant to investors' total return expectations. He selects 6.00%, the approximate mid-point. Mr. Moul then applies a financial leverage adjustment to his DCF results because they are based on market prices of the Gas Group's stock, which imply a capital structure with more equity and less financial risk, but are applied to utility book values, which imply a capital structure with less equity and more financial risk.

The Companies acknowledge Staff and CUB/Cityoppose Mr. Moul's financial leverage adjustment, characterizing it as another form of the "market-to-book" adjustments that this Commission has rejected in past decisions, including the Utilities' last rate cases. Although the Utilities acknowledge that the Commission rejected Mr. Moul's adjustment in the Utilities' last rate cases, they assert that this adjustment is fundamentally different than a "market-to-book" adjustment because it is not intended to maintain any given market-to-book ratio. Rather, Mr. Moul's financial leverage adjustment is intended to correct the error involved in applying a market-based cost of equity to a book value capital structure. The Utilities argue that Mr. McNally's own simplified example demonstrates the reasonableness of Mr. Moul's financial leverage adjustment. If a utility's market value equity is worth $110 and its market-based cost of equity is determined to be 10%, investors expect to earn $1.10 on every dollar they invest. If, however, the Commission applies the 10% market-based return to the utility's book value equity of $100, the utility's return is effectively capped at $10, which means that the utility can earn a return of only 9.1% ($10/$110). Only by adjusting the utility's authorized return to 11% can the utility earn its authorized return.

The Utilities note that since their last rate cases, Staff has modified its DCF methodology. In the Utilities' last rate cases and in many cases prior, Staff relied on the "constant growth" form of DCF model, which assumes one rate of future growth, as opposed to the "non-constant growth" form of the model, which assumes multiple rates of future growth that change over time. *See Peoples 2007* at 78. In several rate cases since then, Staff has used the non-constant growth form of the model, on the basis that the growth forecasts for utilities in the near term (3-5 years) are not sustainable over the long term.

In this case, Staff witness McNally testifies that the Utilities' near-term growth rates are higher than his forecast for growth in the Gross Domestic Product, and therefore use of the constant-growth DCF model gives rise to the "wholly unrealistic scenario" that the Utilities will eventually grow to the size of the entire economy. The Utilities respond that Staff's argument is itself unrealistic because it would take many hundreds of years for that scenario to play out, the investment horizon of investors and analysts is no more than 5 years, and GDP is not an appropriate measure of long term natural gas utility growth.

The Utilities further explain that merely because natural gas utility growth rates are higher than overall GDP growth does not imply an unrealistic long run scenario, as Staff claims. GDP growth is not an appropriate measure of a natural gas utility's long-term growth because the GDP is an average of a variety of component growth rates, some of which are relevant to natural gas utilities and some of which are not, and some of which are higher than others. A prime example is corporate profit growth, which is forecast at a higher level than overall GDP growth between now and 2020. But this does not mean that any individual corporation or group of corporations will eventually outgrow the entire economy, because the GDP growth is an average that is affected by other factors with lower growth rates. Thus, natural gas utility earnings may well grow faster than the GDP in the long run. NS-PGL Ex. PRM-2.0 (Rev.) at 17-18. Finally, the Utilities dispute Mr. McNally's use of "the implied 20-year forward U.S. Treasury rate in ten years" as an accurate measure of GDP growth, arguing that Mr. McNally failed to demonstrate how that rate relates to the GDP growth rate. NS-PGL Ex. PRM-3.0 Rev. at 6-7.

Based on objective sources, including academics cited by Staff and the Federal Energy Regulatory Commission ("FERC"), the Utilities argue that the constant growth DCF model is appropriately applied to natural gas utilities like the Utilities because their growth rates are not significantly higher than GDP growth, much less the two to three times GDP growth that FERC uses as one of its criteria for determining whether to apply the non-constant growth form of the model. Based on these objective criteria, which clearly call for the application of the constant growth DCF model to the Utilities, and Mr. McNally's failure to show, or even analyze, that his growth rates in his multi-stage model met the required characteristics, Mr. Moul concludes that Staff's decision to switch to a non-constant form of the model reflects a subjective decision by Staff to reach lower cost of equity results. Indeed, Mr. Moul calculates the Utilities' cost of equity using Staff's constant growth DCF model and the result was 11.76%, which is over 150 basis points over Staff's non-constant growth DCF result of 10.23% and is comparable to Mr. Moul's adjusted constant growth DCF result of 11.41%. Finally, the Utilities note that the Commission included Mr. Moul's constant growth DCF model as among the cost of equity analyses that formed "an appropriate basis to determine ROE" in their last rate cases.

<u>The Companies' CAPM Analysis</u>

The CAPM determines an expected rate of return on a security by adding to the "risk-free" rate of return a risk premium that is proportional to the non-diversifiable, or systematic, risk of the security. This model requires three inputs: (1) the risk-free rate of return, (2) a "beta" that measures systematic risk, and (3) the market risk premium. For the risk-free rate of return, Mr. Moul uses historical and forecast yields on 20-year Treasury bonds and selected a mid-point of 4.25% based on recent historical trends and current forecast. For the beta measurement of systematic risk, he uses the average *Value Line* beta for the Gas Group, adjusted using the Hamada formula to reflect the application of this market-based measurement to the utility's book value capital structure used in ratemaking. Mr. Moul develops his market premium by averaging forecast data from *Value Line* and the S&P 500 Composite and historical data from Ibbotson Associates, all of which are sources routinely used by investors, analysts and academics. Mr. Moul also adjusts his CAPM result for the relatively small size of the Gas Group, correcting a tendency of the CAPM to understate the cost of equity of smaller companies.

The Companies observe that Staff opposes Mr. Moul's size adjustment, claiming that it "has no theoretical basis." Staff Ex. 7.0 at 43. The Utilities respond that Mr. Moul identified in detail the theory and literature supporting the general proposition that the smaller the firm, the greater its risk. Moreover, Mr. Moul's adjustment is unique to the CAPM because it can significantly understate the cost of equity of smaller firms, including utilities. *Id.* Although Mr. McNally challenges the size/return relationship in general, he does not dispute Mr. Moul's observations about the CAPM's potential to understate smaller firm capital costs.

Mr. Moul challenges Mr. McNally's reliance on a spot quote for 30-year Treasury bonds for the risk free rate instead of *Blue Chip* forecasts noting that, had Mr. McNally selected a date just three weeks later his risk free rate would have been higher. Indeed, using a reasonable forecast of 30-year Treasury bonds with Staff's CAPM yields an ROE of 10.52% instead of the 9.95% Staff obtains with the one-day spot quote. NS-PGL Ex. PRM-2.0 Rev. at 24-25.

Companies' Risk Premium

The Risk Premium model measures the cost of equity by determining the degree to which equity has more risk than corporate debt and adding that "equity risk premium" to the interest rate on long-term public debt. Mr. Moul estimates a 7.00% prospective yield on A-rated utility bonds based on historical and forecasted yields and taking into account the extraordinary impact on the spread in yields between A-rated utility bonds and long-term Treasuries caused by the financial crisis.

Staff's challenges to Mr. Moul's risk premium model center on his use of historical data, and the Utilities address that topic separately and below. The Utilities emphasize that, contrary to Mr. McNally's characterization, Mr. Moul's model is based exclusively on historical data and even when he used such data he evaluated its reasonableness under current market conditions.

Use of Historical Data

As occurred in the Utilities' last rate cases, Staff criticizes Mr. Moul's use of historical data in his analyses. Staff characterizes such data as "outdated" and no longer relevant to the market, and argues that using such data "implies that securities data will revert to a mean," which is an inappropriate measure for the "random walk" of returns.

The Utilities argue that Staff's criticisms about the use of historical data apply with equal, if not greater, force to Staff's reliance on stock price data for the Gas Group from a single day, months in the past.

The Utilities also assert that Mr. McNally mischaracterizes Mr. Moul's use of historical data. Indeed, Mr. McNally goes so far as to charge Mr. Moul with "the mechanistic use of historical data as a direct estimate of the investor expectations that are embedded in cost of common equity estimates." Staff Ex. 21.0 at 2. According to the Utilities, it is Staff that uses historical data "mechanistically" by relying on stock prices from a given day selected by its relationship to when Staff's direct testimony is due. In doing so, Staff gives no consideration to the representativeness of those particular stock prices in light of the historical and forecast information available to and relied on by investors and analysts. Even the academic literature cited by Mr. McNally indicates that daily data "hardly help at all" in estimated expected return. For these reasons, the Utilities conclude that Staff's reliance on "spot" stock prices is arbitrary.

By contrast, the Utilities state, Mr. Moul consulted historical data in addition to current and forecast data to develop his model inputs. In each case, he used sources that are widely available to, and routinely relied on, by investors and analysts. In no sense did Mr. Moul use historical data arbitrarily as Mr. McNally claimed.

The Utilities acknowledge that the Commission has routinely accepted Staff cost of equity analyses based on single-day stock prices. The Utilities urge the Commission to give additional consideration to "return analyses that are based on a broader array of relevant data such as those presented by Mr. Moul." *Id.* at 99. They point out that the Commission relied in part on Mr. Moul's DCF analysis in the Utilities' last rate cases, which was based on Mr. Moul's consideration of historical data for the dividend yield as was his DCF analysis in this case. *Peoples 2007* at 100; *see* PGL Ex. PRM-1.0 at 14-15.

Staff's Financial Risk Adjustment

The Utilities point out that Mr. Moul assembled his proxy group, the "Gas Group," based on an evaluation of a broad range of capital market and financial data on the Utilities and other domestic natural gas utilities over the five-year period 2003-2007. Mr. Moul's evaluation considers factors related to both operating and financial risk. Mr. Moul concludes that on balance, the Gas Group provided "a conservative basis for measuring the [Utilities'] cost of equity because many of the risk factors are lower for the Gas Group and, overall, the Gas Group has lower risk than the [Utilities]." PGL Ex. PRM-1.0 (Rev.) at 12. Staff and CUB/City cost of equity witnesses each used Mr. Moul's Gas Group to apply their own market models.

After finding that Mr. Moul's proxy group, the Gas Group, provided an appropriate proxy of the Utilities' "operating" risk, and using it as the basis for his own analyses, Mr. McNally adjusts his results for the difference he found in "financial" risk between the Gas Group and the Utilities, using the same type of analysis that Staff has used in many prior cases, including the Utilities' last rate cases. Mr. McNally reduces his results for Peoples Gas by 30 basis points and his results for North Shore by 20 basis points.

The Utilities oppose Staff's "financial risk" adjustments, arguing that the adjustments are arbitrary and punitive in a number of ways. First, because Staff's analysis assumes that the Utilities will earn their Staff-audited revenue requirements in full, it understates the Utilities' financial risk because they are by no means guaranteed full recovery of their 2010 revenue requirements, and indeed have significantly under-recovered their revenue requirements set in their last rate cases.

Second, Staff develops hypothetical credit ratings based on this understated portrayal of the Utilities' financial risk and compares them to the Gas Group's average credit ratings, which are based on *achieved* performance. This "apples to oranges" comparison is illogical at best, and at worst punitive, because it assumes ideal *future* financial performance by the Utilities compared to *actual* financial performance by the Gas Group.

Third, Staff wants it both ways: accepting the Gas Group as a reasonable proxy group and then making adjustments for risk variations, without establishing that those risk variations are not offset by variations in other risks. The process of compiling a proxy group involves such considerations and Mr. Moul concludes: "On balance, the cost of equity developed from the Gas Group provides a conservative basis for measuring the [Utilities'] cost of equity because many of the *risk factors are lower for the Gas Group and, overall, the Gas Group has lower risk than the [Utilities]*." *Id.* (emphases added).

The Utilities take issue with Mr. McNally's assertion that Mr. Moul's proxy group analysis is materially skewed by the refunds the Utilities were ordered to pay in 2006 and 2007. Mr. McNally grossly overstates the net income impact of the refunds, which Mr. Moul found to be relatively small as measured by the coefficients of variation of the actual returns. The Utilities also take issue with Mr. McNally's claim that the Utilities' recent credit rating downgrades were due exclusively to the risk profile of their corporate parent, pointing out several aspects of the credit rating agencies' analysis that focus on the Utilities' stand-alone financial strength relative to their peers.

<u>Rider VBA Adjustment</u>

The Utilities oppose Mr. McNally's recommendation to continue the 10-basis-point reduction for Rider VBA because, as he acknowledges, most of the companies in the Gas Group have decoupling mechanisms in place. When the Commission made the adjustment in their last rate cases, the Utilities assert, it did so to accommodate the perceived <u>*change*</u> in the Utilities' risk due Rider VBA. This is supported by the fact that the Commission rejected the Utilities' evidence that utilities in the proxy group already had decoupling mechanisms. Therefore, the Utilities conclude, the Commission effectively assumed that the cost of equity results based on the Gas Group reflected no such mechanisms in place. They reject Staff's position that "the relatively small size of the Rider VBA adjustment is consistent with the fact that most, if not all, of the companies in the Gas Group have some sort of de-coupling rider applicable to at least a portion of their service territories" as revisionist history with no basis in the record of the Utilities' prior rate cases.

<u>Rider ICR Adjustment</u>

The Utilities challenge Mr. McNally's proposed return on equity of 8.06% for the ROE factor in Rider ICR as "grossly overstated." They would have the Commission note that Rider VBA provides for the recovery of almost eight times the amount of Peoples Gas' revenues than Rider ICR does, and yet the Commission adjusted Peoples

Gas' ROE by only 10 basis points for Rider VBA. The Utilities also assert that Rider ICR does not remove the risk of the Commission determining, after the fact, that the costs incurred were imprudent and thus not recoverable; that Mr. McNally did not support his adjustment with any cash flow or other analysis; and, that the adjustment erroneously assumes full implementation of the rider.

2. Staff's Position

Staff witness McNally estimates Peoples Gas' and North Shore's investor-required rates of return on common equity to be 9.69% and 9.79%, respectively. Those required returns include a 10 basis point downward adjustment to reflect the reduction in risk associated with Rider VBA, which was authorized in the Companies' last rate case, but do not reflect the effects of the new riders the Companies' propose.

Mr. McNally measured the investor-required rate of return on common equity with DCF and CAPM analyses. Mr. McNally applied those models to the same Gas Group used by Company witness Moul. To select that sample, Mr. Moul started with the universe of gas utilities contained in the basic service of Value Line, which consists of 12 companies. He then eliminated three companies due to the location or the diversification of their operations. The nine remaining companies, AGL Resources, Atmos Energy, Laclede Group, New Jersey Resources, Nicor, Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries, and WGL Holdings, compose the Gas Group. The table below summarizes Staff's process for determining Peoples Gas's and North Shore's costs of common equity.

	Peoples Gas	North Shore
Gas Group DCF	10.23%	10.23%
Gas Group CAPM	9.95%	9.95%
Gas Group Average	10.09%	10.09%
Adjustments		
Financial Risk	-0.30%	-0.20%
Rider VBA	-0.10%	-0.10%
Cost of Common Equity Before Riders UEA	9.69%	9.79%

Staff contends that a further adjustment would be required if the Commission were to adopt an uncollectibles rider. And, Staff has a separate proposal, in a different context, if Rider ICR were approved

<u>Staff's DCF Analysis</u>

A DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that stock prices embody. The companies in Mr. McNally's Gas Group pay dividends quarterly. Therefore, Mr. McNally applies a quarterly DCF model.

Mr. McNally employs a multi-stage, non-constant DCF model in his DCF analysis. Mr. McNally explains that, while a non-constant growth DCF model is a more elaborate model with additional unobservable growth rate variables that are likely subject to greater measurement error than the analyst growth rate estimates Staff uses in constant-growth DCF analyses, the cost of common equity estimate derived from a constant-growth DCF model is appropriate to use only if the near-term growth rate forecast for each company in the sample is expected to equal its average long-term dividend growth. In this case, the expected near-term growth level for the Gas Group (6.65%) is over 60% greater than that expected for the overall economy, as measured by GDP growth (approximately 4%). Mr. McNally explains that no company could sustain a growth rate greater than that of the overall economy, or it would eventually grow larger than the economy of which it is a part. Moreover, since utilities in particular are generally below-average growth companies, the sustainability of an above-average growth rate is particularly dubious. Thus, given the large difference between the near-term growth rates for the Gas Group companies and the overall growth of the economy, the continuous sustainability of the near-term growth rates for the Gas Group is highly unlikely. Therefore, Mr. McNally concludes that the measurement error associated with a constant-growth DCF analysis exceeds that associated with a non-constant growth DCF model, making the latter model preferable.

Mr. McNally's non-constant growth DCF model incorporates three stages of dividend growth. The first, a near-term growth stage, is assumed to last five years. For this stage, Mr. McNally uses Zacks growth rate estimates as of May 14, 2009. The second stage is a transitional growth period that spans from the beginning of the sixth year through the end of the tenth year. The growth rate employed in the transitional growth period equals the average of the Zacks growth rate and the "steady-state" stage growth rate. Finally, the third, or "steady-state," growth stage commences at the end of the tenth year and is assumed to last into perpetuity. For this stage, Mr. McNally utilizes the implied 20-year forward U.S. Treasury rate in ten years, which reflects current expectations of the long-term overall economic growth during the steady-state growth stage of his non-constant DCF model. An implied 20-year forward U.S. Treasury rate in ten years of 4.59% was derived from the 10- and 30-year U.S. Treasury rates as of May 14, 2009 using the following formula:

$$ {}_{20}f_{10} = [(1+{}_{30}r_0)^{30} / (1+{}_{10}r_0)^{10}]^{1/20} - 1 $$

Where ${}_{20}f_{10}$ = the implied 20-year forward U.S. Treasury rate in ten years;
${}_{30}r_0$ = the current 30-year U.S. Treasury rate; and
${}_{10}r_0$ = the current 10-year U.S. Treasury rate.

Staff Ex. 7.0R at 6-7.

An expected stream of dividends was then estimated by applying the growth rate estimates for those three stages to the May 14, 2009, dividend. The discount rate that equates the present value of this expected stream of cash flows to the company's May 14, 2009 stock price equals the market-required return on common equity. Based on this growth, stock price, and dividend data, Mr. McNally's DCF estimate of the cost of common equity is 10.23% for the Gas Group.

Staff's CAPM Analysis

According to financial theory, the required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Mr. McNally uses a one-factor risk premium model, the Capital Asset Pricing Model, to estimate the cost of common equity. In the CAPM, the risk factor is market risk, which cannot be eliminated through portfolio diversification.

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Mr. McNally combines adjusted betas from Value Line, Zacks, and a regression analysis. The average Value Line, Zacks, and regression beta estimates were 0.66, 0.53, and 0.49, respectively. The Value Line regression employs 259 weekly observations of stock return data regressed against the New York Stock Exchange ("NYSE") Composite Index. Both the regression beta and Zacks betas employ sixty monthly observations; however, while Zacks betas regress stock returns against the S&P 500 Index, the regression beta regresses stock returns against the NYSE Index. Since the Zacks beta estimate and the regression beta estimate are calculated using monthly data rather than weekly data (as Value Line uses), Mr. McNally averages those results to avoid over-weighting that approach. He then averages that result with the Value Line beta, which produces a beta for the Gas Group of 0.59. For the risk-free rate parameter, Mr. McNally considers the 0.10% yield on four-week U.S. Treasury bills and the 4.10% yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of May 14, 2009. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.3% and 5.1%. Thus, Mr. McNally concludes that the U.S. Treasury bond yield is currently the superior proxy for the long-term risk-free rate. Finally, for the expected rate of return on the market parameter, Mr. McNally conducts a DCF analysis on the firms composing the S&P 500 Index. That analysis estimates that the expected rate of return on the market equals 14.01%. Inputting those three parameters into the CAPM, Mr. McNally calculates a cost of common equity estimate of 9.95% for the Gas Group.

Staff's Recommendation

Based on his DCF and risk premium models, Mr. McNally estimates that the cost of common equity for the Gas Group is 10.09%. Mr. McNally adjusts the Gas Group's investor required rate of return downward 20 basis points for North Shore and 30 basis points for Peoples Gas to reflect the lower financial risk of the Companies relative to the Gas Group. He then adjusts the Companies' costs of equity downward by 10 basis points to reflect the reduction in risk associated with Rider VBA, which, along with the same 10 basis point adjustment, was authorized in the Companies' last rate case. Thus, Mr. McNally estimates the investor-required rates of return on common equity to be 9.79% for North Shore and 9.69% for Peoples Gas.

To determine the 20 basis point adjustment for North Shore and 30 basis point adjustment for Peoples Gas to reflect the lower financial risk of the Companies relative to the Gas Group, Mr. McNally first compares the values for the financial ratios that result from Staff's proposed revenue requirement to Moody's guidelines for the regulated gas distribution industry. Based on those Moody's guidelines, Staff's revenue requirement recommendations produce financial ratios that are commensurate with an A1 credit rating for North Shore and an Aa2/Aa3 credit rating for Peoples Gas. In contrast, the Gas Group's average financial ratios for 2006-2008 are indicative of a level of financial strength that is commensurate with a credit rating between A3 and Baa1, which is consistent with the current average credit ratings Moody's has assigned the Gas Group. The Gas Group's lower level of financial strength indicates that it is riskier than either of the Companies. Thus, given the difference between the implied forward-looking credit ratings for the Companies and the average credit rating of the Gas Group, the sample's average cost of common equity needs to be adjusted to determine the final estimate of the Companies' costs of common equity.

Using 30-year utility debt yield spreads published by Reuters, Mr. McNally calculates the yield spreads between the credit ratings implied by the financial ratios for the Companies and those of the Gas Group. This produces yield spreads of 33 basis points for North Shore and 50 basis points for Peoples Gas. He then multiplies those yield spreads by 60%, which is the percent of the overall credit rating that Moody's assigns to the financial ratios. This produces cost of equity adjustments for North Shore and Peoples Gas of 20 basis points and 30 basis points, respectively.

Rider UEA / Uncollectibles Rider

Mr. McNally testifies that Rider UEA would reduce the volatility in, and ensure more timely collection of, bad debt expense and, thus, reduce the Companies' risk. Therefore, if uncollectibles riders are adopted, downward adjustments to the Companies' rates of return on common equity will be necessary to recognize the reduction in risk associated with the authorization of the uncollectibles riders.

To estimate the appropriate risk adjustment for Rider UEA, Mr. McNally employs three distinct approaches. The first approach estimates the effect the adoption of UEA would have on the Companies' Moody's credit ratings, and an adjustment was then calculated from the resulting change in implied yield spreads. The second approach utilizes the Companies' estimates of the effects UEA would have had on the variability of their operating incomes over the last 10 years. That reduction in operating income variability is translated into a new estimate of the beta factor used in the CAPM. The adjustment is then calculated from the change in the CAPM cost of equity estimate resulting from the new beta estimate. The third approach also utilizes the Companies' estimates of the effects UEA would have had on their operating incomes over the last 10 years. However, this approach uses an iterative process of adjusting the cost of equity estimate downward to offset the increased operating income resulting from the adoption of UEA.

These approaches produce adjustment estimates ranging from 10 to 30 basis points for North Shore and from 10 to 120 basis points for Peoples Gas. Based on the midpoints of those ranges, Mr. McNally recommends adjustments to North Shore's and Peoples Gas's costs of common equity of 20 basis points and 65 basis points, respectively, should the Commission authorize the implementation of Rider UEA. Since the Companies have filed for approval of uncollectibles riders under Section 19-145 of the Act in lieu of Rider UEA and Section 19-145 (1) allows the Companies to recover uncollectibles expense for 2008 going forward and (2) limits the Commission's options on review to either approval of the riders as filed or approval of them as modified (220 ILCS 5/19-145(b)), the aforementioned adjustments to the costs of common equity are appropriate for the new uncollectible riders and should be adopted by the Commission.

Rider ICR

Mr. McNally testifies that, in comparison to rate base cost recovery, the recovery of the capital costs of projects run through Rider ICR would be more timely. Further, Rider ICR effectively eliminates the risk that prudent and reasonable project costs will not be recovered. Since Rider ICR would improve the timeliness and certainty of cash flows, it would reduce the Companies' risk. Thus, if Rider ICR is adopted, a downward adjustment to the cost of common equity factor ICR would be necessary.

Specifically, Mr. McNally recommends a 163 basis point adjustment to the base cost of equity that he recommends for Peoples Gas. That adjustment equals one-half of the spread between the current yield for AAA-rated, 30-year utility bonds (6.43%) and Mr. McNally's base cost of equity recommendation for Peoples Gas (9.69%). Mr. McNally reasons that if Rider ICR protected the Company against all risk of non-recovery of investments in the ICR program, a return consistent with AAA-rated long-term utility bonds would be warranted; in contrast, if Rider ICR had no effect on Peoples Gas's risk, the base cost of equity recommendation for the Company would be warranted. Mr. McNally explains that while Rider ICR eliminates the risk of non-recovery of prudent and reasonable costs, the prudency and reasonableness of Rider ICR expenditures is still subject to annual reviews. Thus, Mr. McNally recommends the midpoint between the AAA bond yield and the full cost of common equity.

Staff notes the Companies to claim that Staff's proposed adjustment to reflect the reduction in risk associated with Rider ICR is overstated, in light of the 10 basis point adjustment for Rider VBA, which affects a greater amount of revenue. In Staff's view, however, the Companies' argument betrays a fundamental misunderstanding regarding the central basis for Staff's risk adjustment.

In contrast to the Rider VBA-adjusted ROE, which would apply to rate base assets, Staff wants to make clear that the adjusted rate of return for Rider ICR would only apply to Rider ICR assets. Thus, the comparison the Companies present of the relative sizes of each rider is not relevant. Rather, the relevant comparison is the relative risk of each dollar affected. The risk reduction for each dollar affected due to Rider ICR is greater than that due to Rider VBA. While Rider VBA merely reduces the volatility and uncertainty of a portion of the Companies' revenues, Staff maintains that Rider ICR eliminates both regulatory lag and the risk of non-recovery of prudent and reasonable costs incurred in implementing ICR projects.

Staff observes the Companies to suggest that an adjustment for Rider ICR should be rejected because, even with the adoption of Rider ICR, Peoples Gas remains at risk for non-recovery of projects found to be imprudent or unreasonable. However, Staff's proposed adjustment accounts for that risk. As explained in Staff initial brief, if Rider ICR protected the Company against all risk of non-recovery of investments in the

ICR program, a return consistent with AAA-rated long-term utility bonds would be warranted (i.e., a 326 basis point adjustment). Since the risk for non-recovery of projects found to be imprudent or unreasonable remains, Staff proposed an adjustment only half as large.

Further, Staff notes the Companies would have Staff's adjustment for Rider ICR be rejected because it was not quantitatively developed. The Companies' argument suggests that because the precise effect of Rider ICR cannot be observed and there is no model for precisely quantifying this adjustment, no adjustment should be made. With that logic, the Companies have a disincentive to provide an estimate of their own, and the "adjustment" would necessarily be 0%, despite a clear reduction in risk. Indeed, that is precisely the approach the Companies have taken. Staff believes that the acceptance of such an approach would improperly turn the burden of proof from the Companies and reward the Company for presenting no evidence affirming its position that Rider ICR does not reduce the risk of investment in infrastructure.

Staff explains that there is no established approach for precisely gauging the effect of riders such as ICR, and any adjustment will inevitably be an inexact estimate requiring the analyst's informed judgment. Nevertheless, Staff has provided a reasonable rationale for its proposal.

Staff Criticisms of Companies' Analysis

According to Staff, Mr. Moul analysis contains several errors that led him to over-estimate the Companies' costs of common equity. The most significant flaws in Mr. Moul's analysis, Staff argues, are the: (1) use of historical data in each of his models; (2) inappropriate estimates of the common equity risk premium for his proxy groups in his Risk Premium Model; (3) inclusion of an unwarranted leverage adjustment in his DCF and CAPM estimates; and (4) inclusion of an unwarranted size premium adjustment in his CAPM estimate.

Historical Data

According to Staff, Mr. Moul uses historical data to estimate the current dividend yield in his DCF analysis, the A-rated utility bond default premium and the equity risk premium in his Risk Premium Model analysis, and the equity risk premium in his CAPM analysis. In Staff's view, Mr. Moul's use of historical data is problematic because it favors outdated information that the market no longer considers relevant over the most-recently available information; reflects conditions that may not continue in the future; and implies that securities data will revert to a mean, a proposition which is both questionable and unsupported. Even if securities data were mean reverting, Staff knows of no method for determining the true value of that mean. Consequently, Staff notes that sample means, which depend upon the measurement period used, are substituted. According to Staff, however, any measurement period chosen to estimate the mean is entirely arbitrary, as the measurement period that provides the best estimate of the true mean is unknowable. Thus, Staff claims that the results produced by average historical data are unreliable.

Risk premium analysis flaws

Staff observes that, in determining the equity risk premium, Mr. Moul begins with a 6.23% base equity risk premium estimate representing the historical earnings spread between investment grade public utility bonds and the S&P Utilities Index for the periods 1974-2007 and 1979-2007. Staff notes that he adjusts the 6.23% equity risk premium down to 5.50% in recognition of the lower risk of his proxy group in comparison to the S&P Public Utilities Index. Then, Mr. Moul adds the 5.50% equity risk premium to a projected 6.25% A-rated utility bond yield estimate, which resulted in a cost of common equity estimate of 12.25%.

Staff asserts Mr. Moul's risk premium analysis contains several flaws that undermine the reliability of the resulting estimates. First, Mr. Moul's base equity risk premium estimate is calculated from historical data, which is inappropriate. As discussed previously, the magnitude of an average historical risk premium depends upon the measurement period used, as Mr. Moul's own testimony demonstrates. For example, had Mr. Moul uses the 1966-2007 measurement period, his base equity premium estimate would have been 4.84% rather than 6.23%, which would need to be adjusted downward even farther for the less risky Gas Group. Second, Mr. Moul adds a risk premium measured from an investment grade bond index to an estimate of A-rated bond yield without providing any support that the two are compatible. Third, Mr. Moul provides no quantitative support for the adjustments he made in deriving estimates of the equity risk premium for the Gas Group from the base equity risk premium.

Leverage Adjustment

Staff observes Mr. Moul to contend that, when a company's book value exceeds its market value, the risk of a company increases if the capital structure is measured with book values of capital rather than market values of capital. Staff strongly disagrees. According to Staff, the intrinsic risk level of a given company does not change simply because the manner in which it is measured has changed. In Staff's view, such an assertion is akin to claiming that the ambient temperature changes when the measurement scale is switched from Fahrenheit to Celsius. Mr. Moul's argument confuses the measurement tool with the object to be measured. Specifically, Staff points out, capital structure ratios are merely indicators of financial risk; they are not sources of financial risk. Moreover, Staff emphasizes financial risk arises from contractually required debt service payments; changing capital structure ratios from a market to book value basis does not affect a company's debt service requirements.

Staff would have the Commission note that the Commission rejected the use of leverage adjustments at page 12-13 of it Order for Dockets 01-0528 and 01-0628 and 01-0629 (Consol.) (March 28, 2002); at page 54 of its Order in Dockets 99-0120 and 99-0134 (Consol.) August 25, 1999; and at page 92-93 of its Order in Docket 94-0065 (January 9, 1995). Further, Staff observes that the same leverage adjustment arguments were rejected by the Commission in the Companies' last rate case. Indeed, Staff notes that Order to quite clearly set forth and in great detail, the reasons such a leverage adjustment should be rejected. *Peoples 2007* Order at 95-96.

<u>Size Adjustment for CAPM</u>

Staff notes that Mr. Moul adds a risk premium based on firm size to his CAPM analysis. According to Staff, however, he does not provide any evidence to demonstrate that a size premium is warranted for the utilities. Staff points out that the study reported in Ibbotson Associates, and which forms the basis of Mr. Moul's size-based risk premium adjustment, is not restricted to utilities. Rather, it is based on the entire population of NYSE, AMEX, and NASDAQ-listed securities, which are heavily weighted with industrial stocks. To assume, as Mr. Moul does, that a characteristic drawn from the general (entire market) can be applied to the specific (utilities) is logically fallacious, Staff argues. Moreover, this leaves the entire basis of Mr. Moul's size-based risk premium questionable at best. Staff observes that, in direct contrast with Companies' proposal, a study by Annie Wong, reported in the *Journal of the Midwest Finance Association*, specifically found no justification for a size premium for utilities.

Even for non-utilities, Staff notes, evidence of the existence of a size-based risk premium is not very strong. According to Staff, Ibbotson Associates data shows that, out of a 1926-2007 study period, small stocks consistently out-performed large stocks only during the 1963-1983 period. Further, Fernholz found that a statistical property he termed the "crossover effect" was the primary cause of the difference between large and small company stock returns. That is, when a stock in a large stock portfolio experiences a random negative price change that moves it into a smaller stock portfolio, the negative return is assigned to, and therefore reduces, the return on the large stock portfolio. Conversely, when that same stock experiences a random positive price change that moves it back into the large stock portfolio, the positive return is assigned to, and therefore increases, the return on the smaller stock portfolio. Thus, the "small stock effect" may be less a market return phenomenon than a statistical anomaly due to a modeling deficiency.

Staff notes that a study by Jensen, Johnson, and Mercer found that small stock premiums may be a period-specific phenomenon related to monetary policy. Jensen, *et al,.* observed a size premium during monetary expansions, when the supply of loanable funds increases and investors are more likely to invest in speculative, small company stocks. However, during monetary contractions, as the supply of loanable funds decreases, investors are more likely to switch from speculative investments to safer ones – the well-known "flight to quality" – and no size premium is observed. That investors would consider the smaller firms in the regulated utility sector to be speculative investments is counter-intuitive; Mr. Moul has not supported that premise. Moreover, since Jensen, *et al.*, did not control their measurement of the small stock premium for risk as measured by beta or other means, the "size premium" they analyzed may already be reflected in the betas of smaller companies, rendering an additional risk adjustment such as Mr. Moul proposes unnecessary.

Finally, and as Mr. McNally explains, Mr. Moul's application of the historical size-based risk premiums, as quantified and published by Ibbotson Associates, is inconsistent with the manner in which Ibbotson Associates measured them. While Mr. Moul adds the historical size premium to his CAPM-based risk premium analysis which is based on adjusted Value Line betas, the Ibbotson Associates size-based risk premiums are a function of raw betas. Thus, Staff notes, the "size premium" Mr. Moul adds to his CAPM result is already captured by the adjustment Value Line applies to the betas Mr. Moul uses in his CAPM analysis. Any further adjustment, Staff contends, would be duplicative.

3. CUB/City Position

CUB/City maintain that through their cost of equity experts – and the same for Staff – the Commission is being presented with analyses that rely on objective market indicators, the Commission's preferred estimation models, and fundamental principles of finance. In support of this assertion, CUB/City would have it be noted that the final recommendations of CUB/City expert Christopher Thomas (8.58% - PGL and NS) and those of Staff expert Michael McNally (PGL - 9.69%; NS - 9.79%) were relatively similar and that most of the differences between the numbers were due to questionable techniques Staff used in its cost of equity analyses.

While the recommendations of the CUB/City and Staff experts lie within about 120 basis points of each other, the Companies' proposed ROE (11.87%) was more than 200 basis points higher than any other recommendation in this case. CUB/City contend that the Utilities' outlier position was due to improper inputs and upwardly biased adjustments of the type that the Commission has previously rejected. Further, they point out that Mr. Bodmer's testimony makes transparent the Utilities' efforts to persuade the Commission to rely on: (a) signals from the self-interested investment community and (b) cost of equity determinations by other state utility commissions.

<u>Context For Cost of Equity Determinations</u>

Because of recent dramatic changes in the financial markets, CUB/City present the testimony of Mr. Bodmer. CUB/City explain that Mr. Bodmer has extensive experience and expertise in banking, utility regulation (especially cost of capital issues), and teaching finance and valuation to industry professionals in the U.S. and internationally. CUB/City submit Mr. Bodmer's testimony *not* to make a pinpoint cost of equity recommendation, but rather to apply his expertise to survey current markets and to provide the Commission with an insightful analysis of the market conditions relevant to the Commission's ROE determinations for the Companies. Mr. Bodmer describes the unusual circumstances of the current post-financial crisis market, reviews lessons learned from the recent market upheaval, and identifies new dangers of that environment to ultimately state that:

> My testimony (a) identifies the most important of those perils and provides information on how they can be addressed, (b) provides context for the Commission's examination of the cost of equity analyses and recommendations presented in this case, and (c) offers quantitative validation for the corrective steps I recommend to take account of the lessons of the financial crisis. CUB/City Ex. 1.0 at 3.

CUB/City note that that one peril of the current environment that Mr. Bodmer emphasizes is the danger of having the Commission's attention diverted from financial fundamentals, common sense, and objective evidence of the Companies' risk-based market cost of capital. He stated that "the current crisis actually requires the Commission to return to the basics, rather than to repeat past approaches that take no account of, or are inconsistent with, very different prevailing market circumstances." *Id*. at 3, 7.

CUB/City stress Mr. Bodmer's warning that "the rather chaotic state of the financial markets must not be used as a false basis for excessive ROE recommendations." *Id*. at 3. CUB/City note Mr. Bodmer testimony that the recent market chaos has produced objective evidence that utility stocks are less risky than predicted by some of the inputs selected as inputs for the Companies' analyses.

<u>Rejecting Subjective, Non-Market Approach to Cost of Equity Determinations</u>

CUB/City claim that, as anticipated, the Companies' experts did not use the most objective available data in estimating a proper ROE. Rather, the Companies emphasized appeals to subjectivity and emotion, fear of Wall Street, and comfort in not being different from other commissions.

CUB/City point to Mr. Bodmer's rebuttal testimony, where he states that: "First, Messrs Moul and Fetter asserted that the Commission should focus on what other regulatory bodies have done, rather than on deriving the Companies' real cost of capital from objective market data." CUB/City Ex. 3.0 at 3. Further, Mr. Bodmer observes that the Companies' witnesses also warned that the Commission should be concerned about Wall Street's reaction if its determination (no matter how well-founded) does not follow what other state commissions are doing. *Id*. at 3.

CUB/City claim that while Mr. Fetter "acknowledge[d] that ROEs recently approved in other jurisdictions should not be used to set the Utilities' ROEs here," NS-PGL Ex. SMF 1.0 at 6, he nonetheless relied on his comparison of recent ROE awards to claim that the CUB/City and Staff recommendations are out of the mainstream and would have negative Wall Street consequences for Illinois.

CUB/City argue that Mr. Fetter's table of recently-awarded ROEs actually undercuts the Utilities' ROE position and provides support for the respective ROEs recommended by Staff and CUB/City. At the outset, CUB/City claim that the Commission has rejected such facile comparisons in the past. In Commonwealth Edison Company's ("ComEd") penultimate rate case, i.e., Docket 05-0597, the utility submitted a chart showing 19 returns on equity approved by the Commission and other regulatory agencies during 2004 and 2005. CUB/City further note the utility to have argued that the proposal submitted by Mr. Bodmer in that case was out of line with the 19 recent ROE decisions. The Commission rejected ComEd's argument, finding that:

> ComEd asserts its cost of equity should reflect the costs of equity recently approved for electric utilities in the United States. The cost of equity appropriate to ComEd, however, is specific to that utility. ComEd may not simply adopt the cost of equity set for other utilities scattered around the country, for which the facts and circumstances are not necessarily similar. Rather, pursuant to Section 9-201 of the Act, ComEd must prove that its

> proposed cost of equity is just and reasonable. Final Order at 154, Docket 05-0597 (July 26, 2006).

In this case, CUB/City note Mr. Fetter to have testified that he was not proposing that the Commission use the 30 recent ROE decisions as a basis for setting the proper returns on equity for Peoples Gas and North Shore in these cases. Tr. at 497. Yet, CUB/City would have it known that the Commission addressed a similar matter in the Companies' last rate cases where 54 recent return on equity decisions were cited, and it was argued that the Staff and CUB/City respective return on equity recommendations were too low. *Peoples 2007* at 86. There, like Mr. Fetter does here, North Shore and Peoples Gas asserted that they offered the 54 recently approved return on equity decisions as "guideposts" for the Commission's analysis and "insist[ed] that they 'are not arguing that their returns should be based on the authorized returns of other utilities.'" *Id*. at 89. CUB/City observe that the Commission saw through the Companies' argument in that case, concluding that "[t]he Commission doubts that the Utilities' return comparisons were offered without the expectation that our decision-making would be affected by them. The Utilities are presumably reluctant to directly press for comparison-based ratemaking because of our previous rejection of that approach" in ComEd's rate case in Docket 05-0597. *Id* at 89. According to CUB/City, the Companies presented no persuasive reason why the Commission should deviate from that approach in these cases. Thus, CUB/City assert that the Commission should conclude, as did Staff witness Mr. McNally, that:

> Mr. Fetter does not identify the relative risk, as exemplified by credit rating or any other metric, of each of the utilities involved in those return decisions. Nor does he identify the capital structure that was adopted or the amount of the common stock flotation cost adjustment, if any, that was included in each of those decisions. Without such data, any evaluation of the return recommendations in this proceeding via comparison to the returns authorized in the 30 cases Mr. Fetter cites is *useless*. Staff Ex. 21.0 at 29. (emphasis added).

CUB/City go on to argue that to the extent the 30 recent return on equity decisions have any evidentiary value, they are more harmful to the Companies' witness Mr. Moul's recommended return on equity than they are to Mr. Bodmer's or Mr. McNally's respective proposed returns on equity. At hearing, Mr. Fetter admitted that the average of the 30 recently-approved returns on equity is 10.36%. He also agreed that Mr. Moul's revised return on equity proposal – 11.87% -- is 151 basis points higher than the average of the 30 returns on equity included in his testimony. CUB/City state that the high end of Mr. Bodmer's range of adequate returns on equity, i.e., 9%, is only 136 basis points lower from the average of the 30 return on equity decisions. CUB/City claim that when confronted with that fact, Mr. Fetter essentially admitted that Mr. Moul's recommendation is out of sync with the 30 most recent return on equity decisions, and he recommended that "the Commission look closely and evaluate Mr. Moul's argument and reasoning within his testimony." *Tr.* at 492. Mr. Fetter added that "I think it's important that [the Administrative Law Judges] and the Commission look very closely at both the testimony of Mr. McNally and also Mr. Moul and put it to the test of the type of analysis that this Commission has done since the early 1980s." Tr. at 494.

CUB/City continue to discuss the list. They argue that Mr. Moul's recommendation looks even worse when one removes electric utilities from the list of 30 returns on equity. Mr. McNally calculates that the average return on equity for the gas utilities included in the list of 30 recent return on equity decisions is 10.15%. As Mr. McNally points out, his recommendations for North Shore and Peoples Gas – 9.79 and 9.69, respectively – are 46 and 36 basis points lower than the average for gas utilities included in the list. The high end of Mr. Bodmer's proposed range, 9%, is 115 basis points lower than the gas utility average. In comparison, Mr. Moul's updated recommendation, 11.86%, is a whopping 172 basis points higher than the gas utility average.

CUB/City point out that Mr. Moul's number fares no better when compared to the only Commission decision included in Mr. Fetter's list. According to Mr. Fetter, the Commission approved a 10.17% return on equity for Northern Illinois Gas on March 25, 2009. Cub/City note that Mr. McNally's recommendations for Peoples Gas and North Shore are only 48 and 38 basis points lower, respectively, than the Commission's decision authorized in *Nicor 2008*. They note Mr. Bodmer's high end number is 117 basis points lower and Mr. Moul's number is 169 basis points higher. Further, Mr. Fetter's own data show that: (a) returns for natural gas distribution companies in 2009 have been far lower than the almost 12% estimate made by Mr. Moul, (b) the most recent returns for gas distribution utilities were below 10%, with the latest shown at 9.31%, and (c) the returns for gas utilities are much closer to the recommendations of CUB/City and Staff than to Mr. Moul's. Thus, CUB/City conclude that that Mr. Fetter's list does a far better job of demonstrating that Mr. Moul's recommendation is out of sync with recent return on equity decisions than it does in undermining the recommendations advanced by Mr. Bodmer and Mr. McNally.

CUB/City note Mr. Moul and Mr. Fetter to suggest that the ROE investors expect the Commission to grant is a key factor in driving the Commission's rate-of-return determination. In CUB/City's view, these witnesses appear to warn that a lower-than-expected determination may reduce the Companies' credit rating and the regulatory action may be looked upon unfavorably by Wall Street. CUB./City note Mr. Bodmer to present a hypothetical in his testimony that vividly illustrates why standards such as investor expectations and commission awards are the wrong approach to determining a utility's ROE. This hypothetical, CUB/City explain, makes the point that even when potential investors rationally expect a certain return based on past behavior, or commitments of governing authorities, the return required by the market is still based on the level of risk associated with the investment. Mr. Bodmer testifies that:

> A generous state, say Alaska, with an AAA bond rating decides to guarantee that the return earned by a natural gas distribution company will be 25% through using a series of riders and other mechanisms. Because of the State's AAA bond rating, assume that Alaska can borrow money at an interest rate of 4%. Further, the State enacts a law that mandates the rate of return will be set at 25% and the government will step in to

> guarantee the return even if all ratepayers leave the system. In this case the expected rate of return is 25% while the cost of capital is the interest rate Alaska pays on AAA debt of 4%. If the example were changed so that Alaska guarantees a rate of return of 15% instead of 25%, the cost of capital would still be the interest rate on AAA debt of 4%. *Id*. Mr. Bodmer summarized the implications of this example
>
> In the above hypothetical, the rate of return that is granted is irrelevant to determining cost of capital. The rate of return earned is also irrelevant to determining the cost of capital. Finally, the rate of return expected to be earned is also irrelevant. The only thing that is relevant to the cost of capital determination is the risk of the cash flows, which in this case is driven by the guarantee from the State. The cost of capital in the example is 4%. I*d*. at 13.

CUB/City assert that the Commission's cost-of-service principles require a decision based on cost, as shown by the record evidence and not on investor expectations or actions of another commission. The record evidence in this case, they argue, shows that the range of reasonable estimates for the market cost of equity is bounded by the CUB/City and Staff estimates, with the Companies' recommendation far outside that range.

Correcting Traditional Analyses for the Current Environment

CUB/City explain that Mr. Bodmer's ROE recommendations are not the usual dose of heavy mathematical computations. His testimony takes a different form, and he recommends generally, "that the Commission use more caution, greater scrutiny, and firmer transparency requirements when evaluating recommendations derived from data and models whose significant defects and limitations have recently been revealed more clearly than ever before. Moreover, while some of these deficiencies have always been present, more attention is warranted now because, in the current market environment, they can produce greater distortions."

CUB/City add that Mr. Bodmer's more specific recommendations are the end point of his exploration of deficiencies in the estimation approaches of NS-PGL witness Moul, and focusing mainly on elements of his DCF and CAPM analyses. According to Mr. Bodmer, "Mr. Moul does not test the basic logic of three key variables in his analyses, the growth rate in the DCF model, the growth rate used to derive the return expected by the overall market, and the risk premium in the CAPM." *Id*. at 10. Each of these deficiencies biases Mr. Moul's analyses to increase his cost of equity estimate. Together, CUB/City argue, they make Mr. Moul's recommended cost of equity wholly unsuitable for use in determining a risk-based cost of equity or setting cost-based rates.

Unbiased Betas

CUB/City state that, in discussing bias in Mr. Moul's beta estimates, Mr. Bodmer analyzes the behavior of utility stock prices during the financial crisis. Market data from that period prove some traditional cost of equity theories and models to be flawed. Among them are assumptions about the riskiness of utility stocks relative to the market (the CAPM beta), the illogic of using demonstrably upwardly biased analysts' earnings forecasts, and assumptions about the behavior of credit spreads on corporate and utility bonds.

Mr. Bodmer examines the stock price behavior for firms in Mr. Moul's proxy group. Mr. Bodmer compares the actual performance of those utility firms to the published Value Line betas that purport to reflect stock price behavior relative to the market. According to CUB/City, Mr. Bodmer's results demonstrate that the Value Line betas that Mr. Moul used in developing his CAPM estimate are substantially above the beta estimates implied by actual market behavior of the utilities in his sample.

Separately, CUB/City expert Mr. Thomas conducts an examination of the Value Line betas in comparison to beta estimates from other market observers. Mr. Thomas confirms the same bias, which he captures in a chart of his findings. CUB/City cite to Mr. Thomas's observation that "Mr. Moul relies on only the reported Value Line betas, which have been adjusted for a questionable mean reversion assumption and which are more than 1.8 times higher than the average beta reported by publicly available sources." *Id*. at 7. They argue that Mr. Moul's outlier CAPM result (12.25%) is a predictable consequence of such biased model inputs.

CUB/City assert that Mr. Moul's preference for the Value Line data read by investors apparently blinded him to the large variance -- proved by hard stock price data -- between the Value Line betas and the actual performance of stock prices the betas are supposed to reflect. CUB/City conclude that, given the evidence of record showing a large variance between market performance and Value Line betas and Value Line's outlier position among reported beta estimates, the Commission cannot give weight to estimates based on that data.

CUB/City argue that the lengths Mr. Moul was willing to go to claim that the ROE should be set at the levels investors expect is shown most dramatically by his outlier ROE recommendation. This high recommendation, CUB/City argue, is consistent with his candid admission that he believes "the Commission needs to incorporate in its deliberations investor expectations" and that the result could be a return above that required to induce an investment. CUB/City assert that it is clear that Mr. Moul's objective is not the same as that of other parties and the Commission, i.e., seeking the market cost of equity for the Companies.

Sustainable Growth Rates

Cub/City note Mr. Bodmer to have testified that: "A growth rate that logically cannot persist for an indefinite period is an invalid input to the estimation models." CUB/City Ex. 1.0 at 22. CUB/City witness Bodmer further adds that: "The Commission cannot rely with confidence on earnings growth rate projections made by financial analysts who share the financial community's bias favoring higher utility earnings and whose forecasts have been demonstrably in error." *Id.* at 23. For their part, CUB/City argues that the DCF cost of equity estimates developed by Mr. Moul used analysts' five-year growth forecasts that fail both tests. CUB/City claim that Mr. Moul's forecasts are logically impossible and they are subject to significant bias.

CUB/City point out that Mr. Moul does not put much focus on his insupportable growth rate forecast because, in his view, the validity and reliability of growth forecasts do not affect the subjective expectations of investors. CUB/City note Mr. Moul's statement, that "investors do not need these types of forecasts to make investment decisions" to support its argument. For further support, these parties point to Mr. Moul's statements that growth projections beyond five years are "pure conjecture," and that if investors needed such estimates "some analyst would provide them to fulfill this demand." NS-PGL Ex. PRM 2.0 (Rev.) at 41.

CUB/City note that Mr. Moul's focus on investor expectations was consistent with his overall approach in this case, but claim that he disregard the financial and economic principles supporting DCF estimates. CUB/City observe witness Bodmer to have stated that "Projected growth rates are central to the DCF model. They also can figure in one of the difficult-to-measure factors in the CAPM, namely the expected market risk premium." CUB/City Ex. 1.0 at 22. Further, Mr. Bodmer states that:

> The DCF model estimates the cost of equity capital by assuming that investors who purchase stock are paying a price that reflects the present value of the cash flows they expect to receive from the stock in the future. Using information about the current stock price and expected future cash flows from dividend payments and earnings growth, the model, which is based on the relationships among various factors, estimates the return that investors expect to receive on their investment. CUB/City Ex. 2.0 (Rev.) at 8.

To the CUB/City, it is clear that Mr. Moul recognized the limitations of his chosen growth inputs, i.e., analysts' five year forecasts, but he uses them, contrary to the basic theory underlying the models. CUB/City note that Mr. Moul conceded that growth rate assumptions "beyond the five-years typically considered in the analysts forecast are pure conjecture." NS-PGL Ex. PRM 2.0 (Rev.) at 41. Thus, such growth rate forecasts are not intended to represent rates of growth that can persist indefinitely as the DCF model requires.

CUB/City claim that Mr. Moul did not worry about the sustainability issue and simply assumed that the analysts' forecasted five-year growth rates will persist forever. According to CUB/City, Mr. Moul's objective contravenes the Commission's duty to determine the market cost of capital for the Companies. CUB/City contend that when logical, actually sustainable growth rates are used, they produce dramatically different, and lower, estimates of the cost of capital than the inputs used in Mr. Moul's analysis.

Undistorted Bond Spreads

According to CUB/City, yet another means Mr. Moul uses to inappropriately inflate Companies' cost of equity was to sum the premium of A-rated bonds over government bonds and the premium of the cost of equity over A-rated bonds. As CUB/City witness Bodmer testifies, however, the anomalous circumstances of the current financial market difficulties have distorted some assumed relationships among market variables. As a result, Mr. Moul's premium addition to derive a cost of equity may not yield a valid measure risk of common equity in the today's financial markets.

CUB/City claim that in the current environment, there has been a dramatic increase in the credit spreads on A-rated bonds (from about 1% to 3%). The accepted explanations for the spread would require that of the probability of default or probability of loss in the event of default has changed as dramatically. However, "[f]or a company such as Peoples Gas, which has significant regulatory protections ranging from revenue decoupling to the ability to request rate increases, the supposition that default risk has increased is not a plausible explanation for the increased credit spreads." *Id*. at 34. Also, in the current environment, where there is considerable uncertainty about future inflation (which affects equity less than debt) and where taxes on dividends are lower than those on interest income, the traditional relationship between debt and equity costs is unsettled. Mr. Bodmer therefore concluded that:

> Given the anomalous increase of credit spreads in the current market environment, and the uncertainty about the future rate of inflation, the Commission should not set rates using an anomaly in the financial markets data without examining its causes and whether it actually affects the cost of equity for Peoples [G]as. *Id*. at 33.

<u>Check Fundamentals and Use Common Sense</u>

CUB/City urge the Commission to require analyses that: (1) use unbiased beta estimates that accurately account for the movement of regulated utility shares relative to the current overall market; (2) use sustainable growth rates that are realistic and do not assume continuous returns above the regulated utility's cost of capital; and (3) correct bond credit spread analyses for anomalies in the current financial markets. These are aspects of checking proposed quantitative analyses and recommended cost of capital estimates against fundamental financial and economic principles.

CUB/City argue that, in addition to the challenges presented by current market conditions, the Companies' analyses offer problems of their own making. For instance, they assert, the Companies' DCF and the CAPM models are not applied in a traditional manner, i.e., the leverage adjustment proposed by Mr. Moul is not part of the DCF model supported by its associated theoretical underpinnings. Similarly, CUB/City assert, his size adjustment for increasing beta is not typical in rate proceedings, nor is the method used to derive his risk premium in the CAPM.

CUB/City recommend the Commission to acknowledge that the recent market upheaval has distorted historical relationships and to appropriately adjust its scrutiny of cost of equity analyses on that basis. The steps outlined above, CUB/City argue, are such aspects of checking recommended cost of capital estimates against fundamental financial principles and common sense.

CUB/City assert that common sense should play a larger part in the Commission review for this case, because traditional assumptions and data relationships may no longer hold. Moreover, CUB/City suggest that review of Mr. Moul's significant divergences from customary applications of the estimation models, especially in the aftermath of chaotic security market conditions, will also require a healthy dose of common sense.

CUB/City point out that there are strong indications that market entities usually relied upon for objective information may have failed in that role, with serious consequences for the national economy. Therefore, they argue, the Commission should be aware of the biases of parties and the sources of relied-upon information.

Risks Faced by the Companies Are Mostly Addressed by Riders. Utility Stock Prices Fared Much Better than Stock Prices Generally In the Recent Financial Crisis.

Mr. Fetter testified that CUB/City's recommended return on equity fail to account for the significant risks that the Companies face. He identified such risks as "operational risks, commodity risks, contract counterparty risks, regulatory risks (including regulatory lag and under-recovery of capital costs), capital markets volatility, unforeseen event risk (including infrastructure degradation, or gas explosion risk), and the like" as the types of risks the utilities face. CUB/City argued that Mr. Fetter's slate of risks does not justify a higher return on equity for the Companies.

CUB/City consider it important to note that here are two regulated monopoly gas delivery companies. Unlike unregulated companies, Peoples Gas and North Shore face no competition. Also, unlike unregulated companies, they are guaranteed an opportunity to earn a just and reasonable return on their investments dedicated to service. CUB/City point out that unregulated companies have no such guarantee.

CUB/City adds that, in terms of dollar impact, the largest risk that the Companies face is commodity risk, which Mr. Fetter defined as the cost of natural gas. It is routinely estimated that the cost of gas is usually two-thirds to three-fourths of customers' total bills. Mr. Fetter admitted that each utility has in place a purchased gas adjustment clause ("PGA") and PGAs allow the Companies to recover their respective costs as such costs are incurred. To be sure, utilities face the risk of disallowances during PGA reconciliation proceedings, but such disallowances are rare and, by definition, result from imprudent actions by the utility. CUB/City argue that these facts make plain that commodity risk is not nearly as great as Mr. Fetter asserted. To the extent that utilities do incur disallowances, they should not be awarded a higher return on equity because of their imprudent actions.

CUB/City contends that whatever the risks facing Peoples Gas and North Shore might be, they are belied by Mr. Bodmer's analysis of how utility stocks fared during the recent financial crisis. He testified that after the collapse of Lehman Brothers, stock prices (as measured by the S&P 500) fell by more than 50% (from a high in the fall of 2007 to a low in March 2009). Mr. Bodmer added that "Over the same period, many regulated utility companies have had much smaller stock price declines or have even had stock price increases." *Id*. at 8.

CUB/City point to Mr. Bodmer's analysis of the impact on stock prices that the financial crisis had on the utility sample group Mr. Moul used in his rate of return analysis, and which showed that during the impact of the financial crisis the stock price of the utility group (excluding NICOR, which has shipping assets) fell only 4%. In contrast, CUB and City note, the overall market fell 53% during that same period.

CUB/City further refer to Mr. Bodmer's analysis of the stock price of every utility in Mr. Moul's sample group for the period from January 1995 through April 2009. That analysis, CUB/City point out, conclusively shows that utility stocks are far less risky than stocks generally. Also, they note, during the greatest market upheaval since the Great Depression, stock prices of the utilities set out in Mr. Moul's sample group (excluding NICOR) fell only 4% compared to a 53% decline in the overall market. With these statistics, CUB/City argue, it is difficult to reconcile the claim that the Companies face difficult and far-reaching risks.

CUB/City's Cost of Equity Analyses and Recommendation

CUB/City maintain that the Commission should adopt Mr. Thomas' recommended return on equity for the Companies. CUB/City explain that Mr. Thomas incorporated recommendations from Mr. Bodmer. As such, he avoided the problematic technical inputs and adjustments that Mr. Bodmer identified and discussed.

Based on his quantitative analyses, Mr. Thomas recommends an 8.58% cost of equity based on the DCF and CAPM estimation models preferred in recent Commission decisions, as applied to the proxy group of firms identified by Mr. Moul. His analyses also support his recommendations for an appropriate capital structure, an overall cost of capital, and appropriate conditional adjustment if the Commission approves additional riders for the Companies.

CUB/City note that the market changes since the Companies' last rate cases have been dramatic: a fall of more than 50% in stock prices; smaller, disparate change price changes for utilities; increased demand for low-risk shares (like utility stocks); and Treasury Bond yields below 3% for most of the year. Mr. Thomas testified that these changes have "created conditions in the equity markets that must be accounted for when setting rates for the Companies." *Id*. at 7.

CUB/City's DCF Cost of Equity Analysis

CUB/City points out that Mr. Thomas used the DCF model as his primary cost of equity estimation tool. Taking account of the credit crisis and the discontinuity it has created in the financial markets, especially the uncertainty about future growth rates, Mr. Thomas changed his approach from a single-stage, or constant growth DCF model, to apply a multi-stage or non-constant growth DCF model to the proxy group selected by Mr. Moul. The multi-stage model better accommodated investors' near term focus, future uncertainty from market discontinuities, and the economic and logical ceilings on long term growth rates.

CUB/City observes that in making the judgmental selections that are a part of a DCF analysis, Mr. Thomas was mindful of Mr. Bodmer's cautions and avoided the errors of Mr. Moul's approach. The growth rate inputs to his DCF were sustainable indefinitely, as the model requires. In addition, they were reasonable in the current market context and did not require payout ratios that were inconsistent with capital growth and returns. Mr. Thomas, relying on Mr. Bodmer's testimony and academic research confirms, testified that "the current analysts' 3 to 5 year growth projections used by Mr. Moul do not meet these simple common sense tests." *Id*. at 13.

CUB/City add that Mr. Thomas corrected for the upward bias in DCF results that flows from Mr. Moul's use of current dividends and growth estimates with a proxy group that has a trend of declining payout ratios, which diminishes both dividend and growth.

Instead, Mr. Thomas calculated an internal growth rate that reconciles the tension between payout ratios on the one hand and dividend levels and growth on the other.

CUB/City explain that Mr. Thomas' multi-stage growth analysis assumed (a) short-term (first five years) growth for the proxy group at their average internal growth rate over the last five years, (b) a five-year transition period where growth trends toward the historical average growth rate in real GDP, and (c) the DCF's perpetual long term period, with a very conservative growth rate equal to GDP growth, the maximum sustainable rate.

CUB/City state that the estimate produced through Mr. Thomas' DCF analysis on the proxy group of comparable risk firms chosen by the Companies' witness Mr. Moul was 8.58%.

CUB/City's CAPM Cost of Equity Analysis

CUB/City argue that there are several well-known problems with both the theory and application of the CAPM model that have been the subject of extensive academic study. Those problems encompass each of the three main inputs to the model -- the beta (a measure of firm-specific risk), the expected market risk premium or EMRP (a measure of market risk), and the risk-free rate (the minimum return for any investment).

CUB/City state that CAPM estimates are best used only as a check on the results of DCF model estimates. Ultimately, CUB/City recommended that the Commission use Mr. Thomas's (partially) corrected version of Mr. Moul's CAPM estimate (5.85% - 7.12%), if it is used at all, as a basis for selecting a cost of equity estimate at the lower end of any range of valid estimates.

Beta

According to CUB/City, betas adjusted for an assumed mean reversion, a methodology commonly relied on by Value Line, is one of the principal sources of an upward bias of such adjusted betas. CUB/City argued that the Value Line betas used by Mr. Moul are biased in this way. The assumed reversion of utility betas toward 1.00 means that such low-risk firms, which usually have betas below 1.00, are assumed to become more risky over time. CUB/City asserted that empirical research has not validated that assumption, and it is questioned in the academic literature. This unwarranted adjustment has the effect of improperly increasing betas and the CAPM estimate of the cost of equity.

CUB/City explain that Mr. Thomas made two adjustments to mitigate identified problems with beta estimates. First, he recalculated the betas of the proxy firms to remove the mean reversion adjustment. Second, he used an average of beta estimates from several financial reporting services to recognize the variability among estimates, a common technique preferred over single source inputs. In contrast, Mr. Moul began with the mean adjusted Value Line beta estimates, then adjusted them further upward based on the difference between the market and book value capital structures (his leverage adjustment).

EMRP

CUB/City state that there are two approaches to specifying an EMRP input to CAPM analyses -- academic research and market performance. The superiority of either is a matter of considerable debate. Though the continuing debate suggests that *ad hoc* calculations are unlikely to be superior to prior efforts, the available empirical research does show that such calculations from selective samples of historical data exceeds investors' EMRP.

CUB/City argue that notwithstanding the unreliability of using analysts' forecasts, Mr. Moul used a combination of historical data and analyst's forecasts to compute an EMRP of 8.95%. He also made an adjustment for size relative to the entire market that implicitly assumes that the Companies share risk characteristics with the entire market. Neither adjustment is appropriate and serve only to increase Mr. Moul's cost of equity estimate.

According to CUB/City, Mr. Thomas chose to use the results of the research and analyses performed by unbiased academics over *ad hoc* calculations by interested litigation participants. To accommodate the Commission's past acceptance of calculated EMRP estimates, Mr. Thomas used a range of estimates defined by the high end of academic research results (5%) and Mr. Moul's calculated 8.95% estimate.

Risk-Free Rate

CUB/City state that Mr. Thomas found that the current Treasury bond rate Mr. Moul used to represent the minimum return on the safest available security (4.25%) was reasonable. Using his selected range of EMRPs (5% to 8.95%), and a beta of 0.31 produced a range of CAPM estimates of the cost of equity of 5.79% to 7.01%, which incorporates Mr. Moul's inflated EMRP. In the end, however, CUB/City assert that CAPM estimates are unreliable and strongly recommend their limited, judicious use by the Commission.

Criticisms of the Companies' Add-On Adjustments

CUB/City state that, in addition to Mr. Moul's error of using unsustainable near term analysts' growth forecasts in a single-stage, constant growth DCF analysis, his DCF estimate was further invalidated by two unsupported and inappropriate adjustments to his already inflated DCF results. Mr. Moul proposed a market value, or leverage, adjustment to reflect the difference between the market and book values of the companies in his proxy group and a separate adjustment that purports to account for previously unrecovered flotation costs. According to CUB/City, both adjustments are unnecessary and inflate the cost of equity.

With respect to the leverage adjustment, CUB/City assert that the basic flaw in Mr. Moul's leverage adjustment is that changes in market value do not change the amount actually invested in rate base and on which the utility is entitled to earn. Therefore, no adjustment is necessary. Moreover, market value in excess of book value means a utility's earnings already have exceeded its cost of equity capital. CUB/City noted that recognizing that basic flaw, the Commission has consistently rejected this adjustment, in each of the many guises in which it has been presented, including the Companies' last rate case. There, the Commission stated "Market value is not utilized in this calculation because it typically includes appreciated value (as reflected in its stock price) *above* the Utilities' *actual capital investments*." *Peoples 2007*, Order at 96 (emphasis added). CUB/City argue that "The Commission was correct to reject attempts to inflate the cost of equity capital to maintain the Utilities' market-to-book ratios above 1.0. It should do so again here."

4. Commission Analysis and Conclusions

Referring back to the bedrock principles with which we began this section, the task at hand is to establish reasonable rates of return on common equity for Peoples Gas and North Shore. Traditionally, the Commission evaluates the employment of financial models that quantify the likely cost of attracting capital investment during the times that the rates will be in effect. In this proceeding, both CUB/City and the Utilities provided evidence that we would term as "context" for our decision-making. As prudent regulators, we must be cognizant of this context because each of the financial models is theoretical and has its own limitations. The models are also highly dependent on analyst judgment as to the inputs, and therefore are susceptible to manipulation. Although these models provide the best information of what we need for the purposes at hand, their limitations require that we also consult general financial market information to ensure that the model results presented us are generally consistent with real world conditions, and to guide our determination of reasonable rates of return on equity based on the models that we deem appropriate for our consideration.

While there is no model to produce perfectly reliable results, it has evolved that the standard financial models that the Commission relies on are the DCF and the CAPM. Staff witness McNally has employed each of these models. CUB/City witness Thomas also applied these models. Utilities witness Moul used DCF, CAPM, and an additional model. Recognizing that the cost of equity measure models necessarily employ proxies for investor expectations, the Commission will apply its reasonable and informed judgment as it evaluates the results of the analyses provided by these witnesses.

The setting of utility rates is a legislative function and not a judicial function. *BPI II,* 146 Ill. 2d 175. It is well established that the Commission is more than a mere arbitrator between the utility and parties opposing a rate change. *Citizens Utility Board and the People of the State of Illinois v. Illinois Commerce Commission and Central Telephone Co.*, 658 N. E. 2d 1194 (1st Dist. 1995). Under the comprehensive scheme set out in the PUA, the Commission is to be an active participant. *Hartigan v. Illinois Commerce Commission*, 117 Ill.2d 865 (1987). This means that, contrary to the CUB/City's exception arguments, the Commission has acted properly in developing its own cost of equity for the Utilities.

The matter at hand is not to be resolved by a battle of the experts. Nor are we bound to any witness' proposal as outcome determinative. The only restriction on the Commission is the record, and it is that which we rely upon in exercising our sound and reasonable judgment.

The Proxy Group

Because the Utilities' stock is not publicly traded, we understand that the financial models must be applied to a proxy group of publicly traded natural gas utilities with risk profiles similar to the Utilities. The record shows that in assembling his proxy group, Mr. Moul evaluated a broad range of available capital market and financial data on the Utilities and other domestic natural gas utilities over the five-year period 2003-2007. He considered both the operating as well as the financial risk, and assessed such factors as bond rating, size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and "beta," which is a statistical measure of a stock's relative historical volatility to the rest of the market.

The cost of equity experts testifying for both Staff and CUB/City essentially agreed that Mr. Moul's proxy group provides a reasonable basis on which to base the application of the market models. This proxy group is sometimes referred to as the "Gas Group."

The DCF Analyses

At the start, we note that Mr. Moul, Mr. McNally and Mr. Thomas all use a quarterly DCF analysis. Thus, there is agreement on what could have been an important variable.

As we begin to review the particulars of the respective DCF analyses on record certain differences come clearly into light. As such, we observe that Mr. Moul used a "constant growth" DCF model for his analysis because he found this version to be consistent with approach Staff employed in the Utilities' last rate cases. The Utilities point out, this was the approach accepted by the Commission as one of the analyses that formed "an appropriate basis" to determine the ROE in that proceeding. We observe that the results produced under Mr. Moul's approach is 10.67%

Mr. Moul is not wrong in his observations. The constant growth model has been favored by the Commission for years, and it figured rather prominently in the Companies' last rate case that we decided in 2008. Since then, however, we observe that Staff used the non-constant DCF model in a number of instances and that this also met with our approval. We believe that each case must be decided on the basis of its own merits. In the case at hand, however, we find Staff's use of the non-constant DCF model to be unsupported by the evidentiary record. In contrast to the constant growth version of the DCF model, which assumes one, steady rate of future dividend growth, Staff's non-constant growth model assumes multiple stages of growth on the theory that, given the large difference between the near-term growth rates for the Gas Group and the expected long-term growth of the overall economy, the continuous sustainability of the near-term growth rates for the Gas Group is unlikely. Staff, however, was unable to demonstrate the unsustainability of the analyst growth rates it relied on which we must assume took into account indicators of below average growth associated with the Gas Group, including earnings retention rates and risk/return.

Together with this explanation, however, the Commission notes the testimony of Mr. McNally to have described the multiple-stage non-constant model as being a more elaborate model. As he describes it, this model has additional unobservable growth rate variables that are likely subject to greater measurement error than the analyst growth rate estimates that Staff uses for its constant growth analysis. Mr. McNally continues, to state that “under certain circumstances, the measurement error associated with a constant growth DCF analysis exceeds that associated with a non-constant growth DCF model, making the later model preferable”. Staff Ex. 7.0 at 4. What is lacking in the evidence, however, is a sufficient explanation of what circumstances in the current case would warrant such a preference. We find that the reasons for Staff’s switch to the non-constant growth version of the DCF model require additional inquiry. After consideration of the record, we reject Staff’s position that the non-constant growth form of the model must be used any time it can be claimed that analyst growth rates are not sustainable. Rather we will require a more robust showing that application of the constant model is appropriate.

In any event, Staff witness McNally produced a non-constant growth DCF result of 10.23%. While Staff supported a non-constant growth DCF, it is clear in the evidentiary record that had Staff applied a constant growth DCF, it would result in an estimate of 11.76%. CUB/City witness Thomas used the DCF model as his primary cost of equity estimation tool. This witness changed from using the constant growth DCF model and applied a multi-stage or non-constant growth DCF model in this proceeding. The results of Mr. Thomas’ analysis, however, differed widely from the results stated by Staff’s application of the same model. Mr. Thomas produced an estimate of 8.58%.

Taking review of the results at hand, we find that the most reasonable approach is to average Staff’s unadjusted estimate of 11.76% and the Utilities unadjusted estimate of 10.67% based on the constant growth DCF model. Given the numerous unanswered questions concerning Staff’s conversion to the non-constant growth model, we are not persuaded by Staff’s explanation of what appears to be a fundamental change in its cost of equity methodology. We also find the great disparity between CUB/City’s 8.58% estimate either against Staff’s estimate (for a 318 basis point difference), or against the Utilities’ estimate (for a 209 basis point difference) demonstrates that CUB/City’s estimate should not reasonably be considered.

Before we consider the remaining estimates, the Commission is mindful of there being a certain issue between Staff and the Companies. It concerns Mr. Moul’s use of historical data versus Staff’s use of single-day data in their respective analyses. Staff opposes Mr. Moul’s use of historical data to estimate the current divided yield in his DCF analysis. Among Staff’s criticisms is that historical data favors outdated information that the market does not consider relevant, reflects information that may not continue into the future, implies that securities data will revert to a mean, and any measurement period chose to estimate the mean is entirely arbitrary. That said, Staff does not address itself to the conditions present and surrounding its selection of a single day’s data. There is nothing in the record to inform of these circumstances.

The Utilities argue that spot data is exposed to inefficiencies from a number of sources and that Staff’s reliance on such data without considering what it represents is itself arbitrary. We agree that it would be useful for the Commission to be told the conditions or financial climate of the spot day and whether any of these might cause material market inefficiencies. And, more importantly, we would expect the expert to be acutely attuned to that environment in making a selection. The choice of a spot day may be random or informed and we prefer some reasonable combination of both.

While the Commission has traditionally accepted "spot day" analysis, we are not absolutely committed to this approach. As a recent example, we found Staff's single data point use unsatisfactory for our purposes in these same Companies' 2008 rate case. For purposes of this proceeding we find that taking account of the results of both approaches is valuable to a reasonable determination. This means that the Commission will average the Utilities' unadjusted 10.67% constant growth DCF estimate with Staff's 11.76% constant growth DCF estimate.

The CAPM Analyses

The CAPM has three main inputs: (1) the beta; (2) the expected market risk premium; and (3) the risk-free rate. From the very outset of our review, we pay attention to how these parameters are being developed by Mr. Thomas, Mr. McNally and Mr. Moul.

For his part, Mr. Thomas concluded that CAPM is best used only as a check on the results of DCF model estimates. He did engage the analysis, however, and calculated a beta parameter of 0.31%. He ultimately recommends that the Commission use his partially corrected version of Mr. Moul's CAPM estimate. According to Mr. Thomas, this result is in the range of 5.85% - 7.12%.

Staff witness McNally also applied the CAPM. Notably, he combined adjusted betas from Value Line, Zacks and a regression analysis which he assigned 50%, 25%, and 25% weighting, respectively. Mr. McNally explained the methodologies used to produce each of those beta estimates and concluded that, based on those methodologies, the weightings were appropriate to avoid over-weighting either betas that use monthly data or those that use weekly data. This produced a beta for the Gas Group of 0.59. After imputing all three parameters into the CAPM, Mr. McNally calculated an estimate of 9.95%.

For his application of CAPM, Mr. Moul relied on beta published by Value Line which averaged to 0.69 for the Gas Group. He found this source to be both reasonable and accepted in the investment community. On the other hand, Mr. Moul was unable to confirm the methods, data completion or reliability of other sources like Yahoo! and Reuters. He then applied a leverage adjustment to the published Value Line beta, which raised his beta estimate to 0.82. Finally, when he updated his analysis in his rebuttal testimony, his beta estimate declined by 4 points to 0.78 (the record is silent as to whether, or to what extent, that decline is due to a change in the published beta, itself, or to the leverage adjustment).

At this juncture, the Commission is compelled to note the disparity of the beta parameter as used in the CAPM. We see the Utilities' 0.78 beta includes a leverage adjustment, which, as discussed later, we reject. Far removed and away is CUB/City's beta at 0.31. In between, we find Staff's beta of 0.59. We agree that, in the same way we rely on multiple models to determine the cost equity, Staff's well-considered use of multiple beta sources is beneficial to reduce measurement error from any individual estimate. Moreover, we find that Staff's beta estimate appropriately weights the beta estimates from those three sources. Thus, we adopt Staff's beta estimate of 0.59.

We take a closer look at yet another CAPM parameter in CUB/City analysis that shows itself to be much different. That is the market risk premium. This input, as Mr. Thomas explains it, is either specified as an estimate derived from academic studies of market performance or on the basis of estimates calculated for particular situations. Mr. Thomas favors the former, but it is a view that does not appear to be shared by either Mr. McNally or Mr. Moul.

We note that for the expected rate of return on the market parameter, Mr. McNally conducted a DCF analysis on the firms comprising the S&P 500 index and through this analysis he was provided estimated expected rate of return. For the market premium parameter in his analysis, Mr. Moul averaged forecast data from Value Line, and the S&P 500 composite and historical data from Ibbotson Associates, all of which he noted, are used by investors and analysts accordingly. While not identical, there is a similarity and a heightened sense of reasonableness in the way that both Mr. Moul and Mr. McNally prepared the respective estimates of their inputs. And, we believe the end results will correspondingly be more telling and reliable for it.

After imputing all three parameters into the CAPM, Mr. McNally calculated a cost of equity estimate of 9.95% for the Gas Group. The leverage-adjusted CAPM result that Mr. Moul arrived at from all three parameters is 10.86%. The estimate that Mr. Thomas recommends is the range of 5.85% - 7.12%. Given the disparity between Mr. Thomas' estimate and the results produced by Staff and the Utilities, we will not consider CUB/City's estimate. This leaves both the Staff and the Utilities estimates for the Commission to review. We find the risk-free rates and equity risk premiums included in both of their applications to be reasonable. Moreover, neither shows itself to be superior. Given that we reject Mr. Moul's leverage adjustment, it's clear that Mr. Moul's updated, leverage-adjusted beta of 0.78 cannot be included in the calculation of the cost of common equity we adopt. And, since the record does not indicate what the published Value Line beta was at the time of Mr. Moul's update, we cannot quantify the magnitude of the leverage adjustment included in Mr. Moul's 0.78 updated beta estimate that must be removed for consistency with our rejection of his leverage adjustment. As a result, we are left only with_Mr. McNally's CAPM cost of equity estimate of 9.95%,_which does not take into account concerns in the record with Staff's use of spot data under these circumstances.

The record shows that during the time Staff relied on a spot quote for 30-year Treasury bonds for the risk free rate there was considerable volatility. Indeed, as Mr. Moul noted in his testimony, if Mr. McNally had selected a date just three weeks later his risk free rate would have been higher. According to the record, using a reasonable forecast of 30-year Treasury bonds with Staff's CAPM yields an ROE of 10.52%. NS-PGL Ex. PRM-2.0 (Rev.) at 24-25. Considering the unreliability of solely using spot data in this case, we find using an average of Staff's CAPM cost of equity estimate of 9.95% with Staff's CAPM including *Blue Chip* forecasts of 10.52% is a more equitable result. Thus, we accept a CAPM estimate of 10.24%.

The Risk Premium Model

The Commission will not consider the results of the Utilities Risk Premium model that only the Companies have employed. We have repeatedly rejected this model as a valid basis on which to set return on equity. Our view remains unchanged.

Proposed Adjustments

Staff's Financial Risk Adjustment

We accept Staff's proposed financial risk adjustment of 30 basis points for Peoples Gas and 20 basis points for North Shore. Staff's arguments and Mr. McNally's testimony is persuasive on the matter.

Utilities Proposed Leverage Adjustment

The Commission has rejected the employment of a leverage adjustment many times. There is nothing on this record that persuades us to change course.

Effects of Riders

Rider VBA

With our approval of Rider VBA in the Utilities' last rate cases, the Commission adopted a 10-basis-point reduction to their ROE to account for a reduction in their "risk associated with their cash flow" as compared to the proxy group then being considered. And, we put Rider VBA into place for 4 years. Today, we observe the Utilities to claim that Staff's proposed 10-basis point adjustment to reflect the reduction in risk associated with Rider VBA is not necessary, since the rider has been in place for two years. Staff contends that the purpose of the adjustment is to reflect the fact that the Companies have, and will continue to have, in place a risk-reducing factor that not all the companies in the sample from which the cost of equity was derived have. Further, Staff points out, the Order in the Companies' last rate case expressly stated that, "we find it reasonable to reduce the return on common equity by ten (10) basis points for the duration of the pilot program" and also discussed the quantification of the effect of Rider VBA on the ROE in future rate cases. Order at 99, Docket Nos. 07-0241/07-0242 (Cons.), February 5, 2008.

Having considered all of the arguments presented by both the Utilities and by Staff, the Commission accepts Staff's 10 basis point downward adjustment as reasonable in these premises.

Rider ICR (pertinent only to PGL)

In terms of Rider ICR, the Commission finds Staff's proposed 163 basis point adjustment for the ROE factor to be acceptable. The Commission agrees that Rider ICR reduces Peoples Gas' risk associated with cash flow. And, we find no other methodology or estimate being proposed in the matter.

Rider UEA

Staff witness McNally testified that Rider UEA would reduce the volatility in, and ensure more timely collection of, bad debt expense. Correspondingly, this would reduce the Companies' risk. If uncollectibles riders are adopted, Staff maintains that downward adjustments to the Companies' rates of return on common equity will be necessary to recognize the reduction in risk.

To estimate the appropriate risk adjustment for Rider UEA, Mr. McNally employed three distinct approaches and produced adjustment estimates ranging from 10 to 30 basis points for North Shore and from 10 to 120 basis points for Peoples Gas.

Given that the Companies have filed for approval of uncollectibles riders under Section 19-145 of the Act (in lieu of Rider UE) and that this statute: (1) allows the Companies to recover uncollectibles expense for 2008 going forward; and (2) limits the Commission's options on review to either approval of the riders as filed or approval of them as modified, Staff maintains that adjustments to the costs of common equity are appropriate for the new uncollectible riders.

The Commission agrees with Staff. We adopt a 10 basis point adjustment that lies at the low end of Staff's adjustment range.

<u>Final Conclusions</u>

In the final analysis, the calculation of ROE in these cases will be affect by the following conclusions:

(1) an average of the constant growth DCF estimates of both Staff and the Utilities will be included in this calculation;

(2) an average of Staff's CAPM estimate with and without the *Blue Chip* forecasts will be included in this calculation;

(3) the Utilities' financial leverage adjustment is rejected;

(4) Staff's financial risk adjustment (20 basis points for North Shore and 30 basis points for Peoples Gas) is accepted;

(5) Staff's 10 basis point adjustment for Rider VBA is accepted;

(6) a 10 basis point adjustment for Rider UEA, which represents the lower end of Staff's adjustment range, is accepted; and

(7) Staff's 163 basis point adjustment, applicable only to Rider ICR is approved.

E. Weighted Average Cost of Capital

1. North Shore

Based on the evidence in the record and the applicable legal principles, the Commission approves as just and reasonable an overall rate of return (weighted average cost of capital) for North Shore Gas of 8.19%, calculated as follows:

	Percent of Total Capital	Cost	Weighted Cost
Long Term Debt	44.00%	5.48%	2.41%
Common Equity	56.00%	10.33%	5.78%
Total Capital	100.00%		
Weighted Average Cost of Capital			8.19%

2. Peoples Gas

Based on the evidence in the record and the applicable legal principles, the Commission approves as just and reasonable an overall rate of return (weighted average cost of capital) for Peoples Gas of 8.05% calculated as follows:

	Percent of Total Capital	Cost	Weighted Cost
Long Term Debt	44.00%	5.28%	2.32%
Common Equity	56.00%	10.23%	5.73%
Total Capital	100.00%		
Weighted Average Cost of Capital			8.05%

VII. Weather Normalization – Averaging Period (uncontested)

A. The Record

The Utilities proposed using the average of the previous twelve years of weather data, ending in 2007, which results in 6,095 heating degree days. PGL Ex. BMM-1.0 at 8-9; NS Ex. BMM-1.0 at 8-9. No party disagreed.

B. Commission Analysis and Conclusion

The Commission finds that the proposed average is reasonable and appropriate.

VIII. Proposed Rider ICR (Peoples Gas) – Part I

The Infrastructure Cost Recovery Rider ("Rider ICR"), proposed by Peoples Gas, is designed to recover costs associated with the Utility's replacement of CI/DI main and connecting facilities such as services, meters, and regulators. Under the rider, the recoverable costs are offset by the savings estimated to be generated by the replacement program. Peoples Gas presented evidence supporting the rider. Staff, the AG, and Cub oppose the rider while the City and the Union argue in favor of Rider ICR. The Commission considers all of the testimony and arguments presented.

A. Company's Position.

<u>The Proposed Tariff and Agreed Modifications</u>

Peoples Gas explains that Rider ICR is modeled after, but not identical to, the Commission's rules applicable to water and sewer utilities (83 Ill. Admin. Code Part

656), and it would apply to Service Classification Nos. 1 (residential), 2 (general service, i.e., small commercial customers), 4 (large volume demand) and 8 (compressed natural gas service).

In terms of reporting, Peoples Gas would file in each year an information sheet stating the Rider ICR charge to be in effect for the nine-month period of April through December. According to Peoples Gas, the first Rider ICR charge would be effective April 1, 2011. PGL Ex. VG-1.0 (Rev.) at 35-36; PGL Ex. VG-1.14 (form of report).

After the first effective period, and by March 31 of each year, Peoples Gas would file to initiate an annual reconciliation proceeding. Also, each year beginning in 2012, Peoples Gas would submit to the Commission Staff an internal audit report.

In the course of this proceeding, Peoples Gas agreed to several Staff-proposed modifications to Rider ICR. These accepted modifications, set out in Staff Ex. 15.0, Att. G, are to:

- clarify the wording of the cap that limits recoveries under Rider ICR;
- add more specific language for the annual reconciliation proceeding, namely, a filing date and that the reconciliation will include a determination that costs incurred were prudent, just and reasonable;
- add four specific tests that the annual internal audit would include;
- update the initial percentage in the formula that calculates the Rider ICR charge to specify 90%, rather than 94%, of the Account 383 ("House Regulators") amount in the calculation;
- remove Factor IOM (incremental operation and maintenance expenses) from the calculation because the costs would either be recoverable in other factors in the calculation or minimal;
- exclude incentive compensation costs from the calculation, although Peoples Gas stated that it generally disagrees with Staff's position and agreed only for the purpose of Rider ICR in this proceeding; and
- update, no less than every three years, the "actual savings" factor, which would initially be $6,000 per mile of CI/DI main abandoned during the reconciliation year.

In addition, Peoples Gas notes that Staff withdrew two other proposed tariff changes. Another two of Staff's recommendations are being contested.

<u>Legal Authority for Rider ICR</u>

Peoples Gas observes that in its recent rate case orders, the Commission had the opportunity to review its legal authority to authorize riders. The Commission concluded from the analysis that it has the authority to adopt a rider mechanism in proper situations and under circumstances that are lawful and reasonable. Peoples Gas maintains that, for the same policy reasons the Commission authorized ComEd's Rider SMP and its Advanced Metering Infrastructure pilot (also known as "Smart Grid") (*In re Commonwealth Edison Company*, Docket 07-0566, Order at 137-143 (September

10, 2008), i.e., to encourage investment in the modernization of Illinois' utility infrastructure, the Commission should authorized Peoples Gas' proposed Rider ICR.

Peoples Gas reviews the case law authority in the field beginning with the opinion in *City of Chicago v. Illinois Commerce Comm'n*, 13 Ill. 2d 607, 611 (1958) ("*City I*"), where the Illinois Supreme Court established that the Commission has the authority to approve rate schedules that includes the power to adopt a set formula to recover costs in appropriate circumstances. The Court declared that the Commission is vested with the authority to make "pragmatic adjustments" as part of its ratemaking function.

In reliance on *City I*, Peoples Gas observes that Illinois courts have reviewed and affirmed rider mechanisms in a number of different circumstances. *See City of Chicago v. Illinois Commerce Comm'n*, 246 Ill. App. 3d 403, 410-412 (1st Dist. 1993) ("*City II*") (affirming Commission's approval of a rider for the recovery of the marginal cost of providing non-standard service); *Central Illinois Light Co. v. Illinois Commerce Comm'n*, 255 Ill. App. 3d 876, 885-886 (3rd Dist. 1993) ("*CILCO*"), *affirmed Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111 (1995) ("*Citizens Util. Bd.*") (affirming Commission's approval of rider mechanism for the recovery of coal tar remediation costs); *City of Chicago v. Illinois Commerce Comm'n*, 281 Ill. App. 3d 617, 627-629 (1st Dist. 1996) ("*City III*") (affirming Commission's approval of rider recovery of the utility's franchise costs); *see also Illinois Power Co. v. Illinois Commerce Comm'n*, 339 Ill. App. 3d 425, 434 (5th Dist. 2003) (recognizing that the Commission is authorized to set rates two ways: by base rates and by automatic cost recovery mechanisms such as riders). In *CUB*, Peoples Gas points out, the Illinois Supreme Court re-confirmed its decision in *City I* and established that the Commission has the authority to approve the direct recovery of particular costs through a rider.

With respect to the rule against single-issue ratemaking, Peoples Gas observes that the Commission has concluded that Illinois law prohibits single-issue ratemaking only in the context of a rate case during the phase that balances the utility's cost and allowed revenues, and is not applicable to a proposed rider that merely facilitates direct recovery of a particular cost without upsetting the utility's revenue requirement. The rule against single-issue ratemaking applies only in the context of a general rate case, such as the present proceeding. *See Archer-Daniels-Midland Co. v. Illinois Commerce Comm'n*, 184 Ill. 2d 391, 401-402 (1998); *Citizens Util. Bd.*, 166 Ill. 2d at 138. The rule is based on the principle that it would be improper to consider changes to one component of a utility's revenue requirement (operating costs plus rate base times rate of return on capital) in isolation because a change to one item of the revenue formula could be offset by a corresponding change in a different component of the formula.

Based on this authority, Peoples Gas argues that the rule against single-issue ratemaking is not violated where a rider merely facilitates the direct recovery of particular costs in a manner that either has no direct impact on or accounts for any corresponding changes to the components underlying the utility's rate of return so that there is no under- or over-recovery.

In the situation at hand, Peoples Gas maintains that approving Rider ICR is an appropriate exercise of the Commission's discretionary authority based on the evidence of its benefits as shown by Peoples Gas and because the rider, as structured, would not violate the rule against single-issue ratemaking. This is so, Peoples Gas argues, because unlike the earlier version of the rider that was proposed in its previous rate case, Rider ICR as proposed in the instant proceeding includes a factor for offsetting savings generated by the accelerated program, thus preventing any overstatement of Peoples Gas' overall revenue requirements by Rider ICR. Peoples Gas further points out that, at the suggestion of Staff, this provision of Rider ICR has been further modified to require the re-calculation of this savings factor no less than every three (3) years, with the Commission and other parties free to initiate proceedings to do so more frequently if deemed necessary. In light of all these features, Peoples Gas argues, Rider ICR does not violate the single-issue ratemaking rule.

Rider ICR as proposed in this proceeding presents an appropriate situation for the Commission to use its discretion to authorize the use of a rider to facilitate the direct recovery of particular costs -- a portion of the costs of the main replacement program -- that will not upset Peoples Gas' revenue requirement because the proposed mechanism provides for the flow back of savings generated to customers.

Peoples Gas also notes that Rider ICR, as proposed here, corrects another legal concern raised by the Commission when reviewing the earlier version of Rider ICR in the Company's 2007 rate case. Whereas that early version of the rider contained a provision that would prohibit the Commission from exercising its statutory power to initiate a proceeding under the PUA requiring Peoples Gas to carry the burden of proving the reasonableness of Rider ICR, the specific rider being proposed in the instant case does not contain any provisions of this nature. In its testimony, Peoples Gas sets out its belief the Commission (as well as other parties) would remain free to initiate whatever procedures are authorized under the PUA in the future with respect to Rider ICR if it is approved.

The Costs and Benefits of Accelerated System Modernization

In the Order entered on its last rate case, Peoples Gas points out, the Commission provided specific guidance and direction pertaining to the evidence it needed to evaluate and approve Rider ICR. In this proceeding, Peoples Gas asserts, the testimony of Salvatore Marano of Jacobs Consultancy, addresses each of the area of information that the Commission specified as necessary in the 2008 rate case Order. Peoples Gas would have the Commission know that Mr. Marano is a licensed professional engineer having 18 years of experience in the operation of gas utilities and 12 years of experience as an expert for both utilities and public utility commissions on numerous matters, including CI/DI main replacement projects.

Peoples Gas presents the testimony of Mr. Marano as it is material to each of the categories that was outlined by the Commission at page 162 of its 2008 Peoples Gas rate case Order.

A detailed description and cost analysis of the proposed system modernization

Peoples Gas explains that Mr. Marano's testimony describes the physical nature of the modernized system as well as the expected approaches by Peoples Gas to implement the modernization.

At the outset of his testimony, Mr. Marano describes Peoples Gas' existing system and explains how the aging CI/DI mains require a higher level of risk management and generate a larger number of main leaks requiring repair. Mr. Marano explains that these materials will be replaced by polyethylene ("PE") pipe materials and, when necessary, coated cathodically protected steel, which are "state-of-the art" in terms of gas main and service materials. According to Mr. Marano, the PE pipe being installed has a life expectancy of 80 plus years and is not subject to corrosion or stress-related cracking.

Mr. Marano details how Peoples Gas' system modernization will upgrade its distribution network from a low-pressure system to a medium-pressure system. The low-pressure system is a legacy from when customers received gas manufactured from coal and is prone to outages caused by water infiltration. No low-pressure systems are installed today. Indeed, in the future, standard residential appliances may not be compatible with a low-pressure system. Peoples Gas' upgraded system will provide customers with a modern medium-pressure distribution system that will provide many new functionalities and benefits.

Mr. Marano also provided a detailed explanation as to the expected and recommended approaches to the accelerated main replacement program. His testimony illustrates that, by accelerating and thus replacing larger amounts of main each year, Peoples Gas could add a zonal approach to the program to allow for greater economies of scale and coordination with the City and other utilities with respect to their infrastructure projects.

Mr. Marano also prepared and submitted a detailed cost analysis on behalf of Peoples Gas to show, as best as could be projected, what the construction costs would be for replacing its CI/DI mains at the current rate, which would have the replacement completed in the year 2059, and under a nineteen-year accelerated replacement scenario which would have Peoples Gas complete its replacement program by the year 2029. Mr. Marano's analysis concluded that the accelerated main replacement program would cost $432 million (in 2010 dollars) less in construction costs than Peoples Gas' current main replacement program over what would be its 49-year life-span. After subtracting the incremental costs (termed "Incremental O&M" in the analysis) of program management and labor (such as meter installation work) associated with the accelerated program that are projected to be $159.7 million, Mr. Marano projected that the net construction cost savings from accelerating the main replacement program construction would be $272.3 million.

Mr. Marano further testified that the new distribution system would provide savings in Peoples Gas' ongoing operations and maintenance ("O&M") costs by substantially reducing the amount of leak repairs, leak surveys, leak rechecks, emergency responses, regulator station inspection and maintenance, vault survey and maintenance, lost gas and inside safety inspections. Mr. Marano testified that compared to the scenario in which Peoples Gas continues its current main replacement plan, the accelerated scenario would generate a total of $244 million in O&M cost savings over that same time period.

An identification and evaluation of the range of technology options considered and analysis and justification of the proposed technology approach

Peoples Gas provided evidence to show that the materials to be used in replacing its aging CI/DI mains -- PE and coated cathodically protected steel -- are the state-of-the-art in gas main and service materials. Likewise, the upgrade to a medium-pressure from a low-pressure distribution system will bring Peoples Gas current with the standard for natural gas distribution systems, as low-pressure systems are a legacy of a bygone era, as low-pressure systems are no longer being installed and appliances for such systems being discontinued. A medium-pressure system also is less costly to construct because it allows for smaller diameter pipe to be used, and can take advantage of PE pipe, which is less expensive than coated steel pipe.

Mr. Marano further discusses the technology options used and alternatives considered by Peoples Gas, and explains that the company's use of directional drilling technology reduces construction restoration costs and eliminates the need to dispose of spoil caused by open trenching. Mr. Marano also described the options available for approaches to pipe replacement and explains why he recommended the use of a zonal approach to create economies of scale that may create further cost savings as well as provide benefits to the City and other utilities via the coordination of their respective infrastructure projects. Peoples Gas also provided testimony explaining how its "double decking" of mains -- that is, placing main in the parkways on each side of a street rather than a single main in the middle of the street -- would create several benefits:

a remove gas main from the congestion of utilities in the street;
b reduce future maintenance costs;
c reduce the potential for excavation damage to gas facilities from third parties;
d reduce the average length of service lines and number of long side services; and
e reduce program installation costs.

A detailed identification and description of the functionalities of the new system, related both to system operation as well as on the customer side of the meter, and an identification and justification of functionalities foregone

Peoples Gas introduced a considerable amount of evidence as to the functionalities of the new system as to its operation and to customers and other interested parties, and the benefits provided by those functionalities. With respect to the old low-pressure system, Peoples Gas' expert Mr. Marano testified that there will not be any functionalities foregone when that system is replaced.

As for the new system, Mr. Marano testified that it will be simpler, more reliable and be more optimal in design. Over 300 medium to low pressure regulator stations, along with their maintenance costs, can be eliminated and replaced with 54 new high to medium pressure regulator stations with a common design that will reduce construction costs and future maintenance costs. Water infiltration common with low-pressure systems, which can cause outages, will be eliminated. The moving of meter sets to outside the house will provide greater access and improved safety, and the new meters combined with the constant pressure provided by the modernized system will measure gas usage more accurately. From a system operation and maintenance perspective, the new regulator stations will be in the parkway, providing safe access and reduced impact on traffic. This will also benefit the City, which will encounter fewer regulator vaults that could impede street construction. Eliminating the medium to low pressure regulator stations will reduce the amount of training, inspection and maintenance necessary, thus also reducing the potential for human error. The increased use of PE pipe will reduce the risk of leaks caused by corrosion and reduce the amount of pipe required to be leak surveyed annually.

Customers also will benefit from the functionalities of a modernized system. Customers will no longer need to install costly gas boosters and safety back-check valves to provide elevated pressures for modern energy efficient appliances and back-up generators. Service lines will have excess flow valves -- unavailable with a low-pressure system -- which will reduce the potential property damage caused by a damaged service line. Furthermore, emergency response personnel, such as the City's Fire Department, will be able to shut off gas to a building from the outside meter sets, which potentially could reduce property damage in fire and other emergency situations.

The evidence illustrated the following additional beneficial functionalities that the modernized system will provide:

a fewer joint leaks because PE pipe is fused and steel pipe welded;

b medium-pressure meter sets will have a pressure regulator with overpressure relief and meter shutoff valve before the meter;

c meters relocated outside will eliminate the need for inside safety inspections;

d the use of PE pipes will enable crews to isolate gas leaks quickly by closing an existing valve or squeezing off the pipe upstream and downstream from the leak; and

e moving gas mains out of the streets and into parkways will result in a reduction of third-party excavation damage and accidental gas line cuts and an increase in worker safety.

Analysis of the benefits of the system modernization, both to system operation as well as to customers, including reductions in system costs, and an analysis of the range and benefits of potential new products and services for customers made possible by the system modernization

Peoples Gas also provided evidence that the system modernization will provide additional benefits to customers, including enhanced system safety, reduced system costs, potential new products and significant environmental benefits. Furthermore, Peoples Gas submitted evidence that the acceleration of Peoples Gas' main replacement program will create additional jobs.

As Mr. Marano describes in detail in his testimony, Peoples Gas' aging CI/DI mains are comprised of materials that pose a risk of catastrophic failures, which present risk to customers and Peoples Gas' personnel that the company must manage. While Peoples Gas does a good job managing these risks, these materials ultimately will fail and must be replaced, with the costs of managing this system continuing to increase as it ages. Peoples Gas' proposed system modernization will eliminate the risks, along with the risk management costs they require, posed by the existence of these higher-risk materials in the Company's distribution system.

The evidence shows that modernizing Peoples Gas' distribution network will generate savings in Peoples Gas' O&M costs that will benefit customers. Mr. Marano's analysis projected that if Peoples Gas accelerated its main replacement program, those O&M savings would amount to $244 million between the years 2011 and 2059 because of a substantial reduction in the amount of leak repairs, leak surveys, leak rechecks, emergency responses, regulation station inspection and maintenance, vault surveys and maintenance, lost gas and inside safety inspections. Customers would further benefit from the synergies and efficiencies in system maintenance by no longer being inconvenienced by the need to schedule inside safety inspections, suffer from water infiltration outages or the freeze-up of low-pressure risers.

A medium-pressure system upgrade will enable customers to more easily use technologies and appliances, particularly high-efficiency appliances, not compatible with the low-pressure system now in place. Currently, to operate these types of appliances and natural gas-fired back-up generators on the low-pressure system, customers are required to install and maintain electric-powered gas pressure booster systems which can cost between $20,000 and $50,000.

This would be important for facilities such as schools, hospitals and emergency services providers, which are required by Chicago code to have back-up generators installed. Those facilities now located on the low-pressure system would need a pressure booster system installed to use a natural gas-powered generator, or else use gasoline or diesel powered versions which are less environmentally friendly and potentially dangerous.

A medium-pressure system would allow all customers to install high-efficiency appliances such as tankless water heaters, fan-assisted heaters, home generators and commercial-grade cooking appliances. Not only is the availability of such high-efficiency appliances important for the environment and energy-conservation, but they will help customers save money as well. For example, a tankless water heater is estimated to cost $265 to operate a year, as opposed to $326 for a 40-gallon gas heater and $453 for a 40-gallon electric tank.

Another financial benefit to customers of the new medium-pressure system will be that it will allow customers to use corrugated steel piping, which is more economical and will allow customers to reduce their building construction costs.

Mr. Marano's testimony detailed other significant environmental benefits of system modernization as well. The elimination of Peoples Gas' CI/DI mains and their replacement with PE and protected steel pipe will dramatically reduce the amount of greenhouse gas emissions from the Company's mains. Based on a study by the U.S. Environmental Protection Agency, Mr. Marano estimated that by accelerating the main replacement program, Peoples Gas could further reduce the emission of greenhouse gases by approximately 10,500 Mcf per year. Upgrading the system to medium-pressure also will eliminate the need for the collection, testing and disposal of water that enters the gas distribution system.

Another important benefit of accelerating the main replacement program to the City would be the creation of a substantial number of jobs, as additional people will be needed to perform the construction work (both internal and external to the Company), the meter installations and relights of service and the management of the work. When questioned at the hearing as to whether Peoples Gas could accelerate the main replacement program without hiring additional personnel, Mr. Marano testified: "Absolutely not."

Peoples Gas further notes that even the AG-CUB witness who testified in opposition to Rider ICR agreed on cross examination that the decision on whether to implement an infrastructure investment program such as Rider ICR should not be based solely on cost, but on factors such as safety and reliability, as well. Peoples Gas argues that the evidence demonstrates that Rider ICR would generate not only financial benefits for customers in the form of construction and O&M cost savings, but additional benefits to customers such as enhanced safety, energy conservation, increased functionalities and appliance choices and reduced environmental impacts. Peoples Gas thus concludes that the evidence in the record strongly weighs in favor of authorizing Rider ICR to help bring these benefits to customers sooner than otherwise possible.

B. City's Position

The City observes that Peoples Gas has proposed Rider ICR to recover the costs of accelerating its cast iron and ductile iron main replacement program. The rider would apply to service classifications 1, 2, 4, and 8 and would become effective in April 2011.

The City focuses on the testimony of Peoples Gas expert Salvatore D. Marano and his account of the Utility's proposal to accelerate the replacement of its antiquated cast iron and ductile iron mains, which are part of PGL's legacy low-pressure system. The City notes Mr. Marano's testimony to reveal that portions of the cast iron and ductile iron mains are more than 100 years old. The City observes Mr. Marano to explain that it is necessary to replace Peoples Gas's cast iron and ductile iron mains because of potential safety issues. Mr. Marano stated that cast iron and ductile iron mains "are higher-risk materials because of their unpredictable and catastrophic failure mode." Mr. Marano added that Chicago's "climate and geography ... [present] strong factors that could adversely affect pipe integrity. The[se factors] include poorly drained soils, large temperature variations, and conditions favorable for frost heave, which is when soil expands and contracts due to freezing and thawing." Mr. Marano explained that "Accelerating the replacement of these higher-risk materials will increase system safety and reduce the likelihood of subjecting the public and customers to the adverse effects of pipe failures."

The City also considers Commission Staff's Energy Division director Harold L. Stoller's testimony concerning Peoples Gas' proposal to accelerate its cast iron and ductile iron main replacement program. The City notes that Mr. Stoller confirmed the safety issues raised by Mr. Marano associated with the continued use of the Utility's antiquated cast iron and ductile main system. When asked if he was convinced that the Utility's main replacement program should be accelerated, Mr. Stoller testified "I am absolutely convinced. What Mr. Marano has described is a gas distribution system which is in serious need of major renovation to keep it safe for the citizens of the City of Chicago." Describing Peoples Gas' cast iron and ductile iron main system, Mr. Stoller said "that it is old, it is antiquated, and it is approaching the point that further aging and deterioration will eventually cause replacement to maintain public safety to become an emergency matter rather than one which can be reasonably planned and executed." In such circumstances, Mr. Stoller concluded that he is convinced that "Peoples Gas should begin the replacement program very soon to avoid the possibility of a later emergency situation."

The City agrees with Mr. Stoller's recommendation on this point. The City observes that while neither Mr. Marano nor Mr. Stoller testified that the Utility's cast iron and ductile iron main system is currently unsafe or in any immediate danger, the tenor of the comments are of great concern to it. The City stated that one of, if not its most important functions is to protect its citizens. Given that failure of Peoples Gas' delivery system could be catastrophic to City residents, the City asserts that it is of utmost importance that the system is as safe as reasonably possible.

The City cited Peoples Gas witness James F. Schott's statement that Rider ICR will allow the Utility to proceed with an accelerated main replacement program with greater cost recovery certainty. In other words, Rider ICR will allow Peoples Gas to replace its low pressure system more quickly, without the financial uncertainty that accompanies having to wait until the Utility's next rate case to recover the costs associated with modernizing its system. Given the magnitude of the potential safety issues, the City supports removing any disincentives that might cause Peoples Gas to not replace its legacy low-pressure system as expeditiously as reasonably possible.

The City notes that Peoples Gas's proposed accelerated main replacement program represents a significant effort to bolster and improve the state of infrastructure in Chicago. Improving this critical aspect of Chicago's infrastructure will allow Peoples Gas to continue to provide safe service.

The City is mindful utilities are more frequently seeking to recover expenses -- and in some cases, capital costs – through riders. It observes that Illinois courts have stated that riders are to be used in extraordinary situations and that requests to recover costs through riders require special scrutiny. *See, City of Chicago v. Illinois Commerce Comm'n,* 281 Ill.App.3d 617, 627 (1st Dist. 1996). The rationale for utilities seeking to recover more and more costs through riders seems obvious – rider recovery reduces their risks. However, reducing utility risk exposure increases risks for customers. Moreover, increased cost recovery is inconsistent with the manner in which utilities have been regulated for many decades. The City stated that increased use of riders threaten effective and thorough regulation of monopoly services.

That said, the City supports Rider ICR. The City argued that replacing legacy mains as expeditiously as reasonable is an ***extraordinary*** situation. It also is an extremely important safety matter for the City. Given that some of the Utility's mains are at least 100 years old, the City concluded that Rider ICR should be approved to eliminate a potential impediment to their accelerated replacement.

C. AG's Position

The Company Failed to Prove a Need for Rider ICR or that Extraordinary Rate Recovery In General Was Appropriate.

Under Illinois law, the AG points out, a utility bears the burden of proving that proposed changes in rates are just and reasonable. And, it explains, the process used to evaluate and measure the cost of service and resulting revenue requirement is the rate case, in which a balanced review of jurisdictional expenses, rate base investment, the cost of capital and revenues at present rates can be undertaken at a common point in time – the test year. *BPI II,* 146 Ill.2d 175 at 238.

According to the AG, Peoples Gas' proposed Rider ICR would completely alter the way the Company finances infrastructure investments and the timing of when ratepayers pay for them. Rather than financing plant through internally generated funds and debt and then earning a return on that used and useful investment after filing a rate case, the AG maintains that Peoples Gas' proposal would force ratepayers to pay a return of, and on, forecasted distribution plant investment up front at a rate of the Utility's own choosing without the synchronized, balanced review of all elements of the revenue requirement -- a key component of traditional regulation that is missing when riders are used to recover designated expenses. Financing plant in this manner would necessitate a drastic departure from past regulatory practice. While the Commission's decisions are not res judicata, the AG observes that where the Commission's decisions drastically depart from past practices, they are entitled to less deference. *Business & Professional Peoples for the Public Interest v. Illinois Commerce Comm'n,* 136 Ill.2d 192, 228 (1989) ("*BPI I*").

The AG contends that the evidence presented by Peoples Gas does not address the need for a special rider tariff to recover costs associated with infrastructure replacement. The only direct testimony that addresses the alleged need for a special rider, the AG observes, is PGL witness James Schott's statement that:

> the financial crisis has made capital more expensive to obtain. This makes the need for rider treatment, with the greater level of certainty of recovery on and of the investment in cast iron main, even more critical to keep the capital costs associated with the infrastructure improvement reasonable.

The AG notes, however, that Peoples Gas stated unequivocally in response to data requests that the absence of an automatic rate adjustment rider for capital costs has not affected the Company's access to capital. Peoples Gas also admitted in a discovery response that it has not failed to make needed investments in its system due to lack of capital or the inability to automatically recover capital costs through a rider.

The AG observes that Staff witness Kight-Garlisch noted that the Company identified two other methods that allow "prompt and fair rate recovery" -- traditional rate case fillings with a future test year or a deferral mechanism – both of which were rejected in favor of Rider ICR. Ms. Kight-Garlisch testified that the Company provided no analysis to support its need for Rider ICR to raise sufficient capital to provide adequate, efficient, reliable and safe utility service at a reasonable cost.

According to the AG, Staff witness Lazare was particularly critical of Mr. Schott's assertion that Rider ICR would somehow "keep the capital costs associated with the infrastructure improvement reasonable." Mr. Lazare noted that Mr. Schott provided no specific evidence concerning what the capital costs for the program would be with and without Rider ICR. The Company's responses to various Staff and AG data requests confirmed this fact.

AG/CUB witness Scott Rubin similarly concluded that Peoples Gas failed to make a case for Rider ICR adoption. He testified that Peoples Gas failed to show that the existence or absence of Rider ICR would affect its cost of capital, impact its capability to finance necessary improvements, or jeopardize its ability to provide safe and reliable service to its customers. Peoples Gas indicated in responses to AG data requests that the Company has neither conducted an analysis to determine whether Peoples Gas would be "unable to earn its authorized return if it adopts an accelerated main replacement program under traditional regulation (without a rider)" or analyzed the impact of its proposed Rider ICR on earnings attrition.

According to the AG, Peoples Gas' response to these criticisms was to argue that "the Commission laid out a clear 'road map' or set of guidelines of its expectations of what is required for approval of such a rider", it had followed those guidelines and provided the necessary information requested therein. PGL witness Schott concluded: "The Staff and intervenor responses failed to identify any shortcomings in the Company's efforts to meet the Commission's ICR guidelines. Thus, it would appear that Peoples Gas has bet the requirements outlined by the Commission Docket Nos. 07-0241/07-0242 Cons." *Id.* But even PGL witness Marano, who presented PGL's cost benefit study of accelerated main replacement, admitted that his analysis did not consider whether a rider is an appropriate cost recovery mechanism.

The AG maintains that PGL's belief of what evidence is needed to support a Commission finding that approves rider treatment of infrastructure investment is simply wrong. In its Order in the last Peoples/North Shore rate case, the AG points out, the Commission rejected a similar rider proposal, and noted that "Insofar as Peoples Gas would like to quicken the pace of system modernization, it is free to craft a concrete and sustainable proposal for doing so, and to request base rate recognition of associated investments." *Peoples 2007* at 161. The Commission also stated that the Company's previous Rider ICR proposal, "reflects a need for the Commission to provide guidance to utilities on the information the Commission needs, *at a minimum,* to evaluate system modernization proposals, beyond Part 656 and Section 220.2 of the Act." *Id.* at 162 (emphasis added).

Nothing in the Order's language, the AG contends, suggests that the mere presentation of a cost/benefit analysis of accelerated main replacement, or the other information it outlined, would somehow guarantee adoption of a proposed rider, as Mr. Schott's testimony, and the Company's failure to respond to Staff and Intervenor witness criticisms, suggests.

According to the AG, Staff witness Lazare highlighted the defect in the Company's evidentiary presentation, noting that the need for main replacement acceleration and how such a program should be funded are two distinct questions:

> It is not clear how Mr. Marano's testimony supports the adoption of a rider to collect infrastructure costs. He focuses instead on the need for an accelerated program to replace the current network of cast iron and ductile iron mains and how that can best be accomplished. However, he does not discuss why a rider mechanism is needed to recover the associated costs. Mr. Marano is clear on this matter. Mr. Marano states the 'analysis of regulatory mechanisms to allow companies to be recover their costs of system modernization as well as to flow reduced system costs back to customers' is presented by Company witnesses Schott and Grace.

Neither Mr. Schott nor Ms. Grace, the AG contends, provided justification for rider treatment of future infrastructure investment.

AG/CUB witness Rubin provided support for the rejection of Rider ICR and retention of the traditional method of financing capital investments. He noted that riders are particularly inappropriate to use for the recovery of capital costs related to new infrastructure investment. He explained that utility rates are set based on a synchronized examination of all aspects of the utility's costs of service and sources of revenue, as well as other considerations such as the quality of service and efficiency of management, and that such synchronization is the reason why a test year is used in ratemaking. The synchronization of adding new investment, Mr. Rubin noted, also requires adjustments to rate base, depreciation expense, other O&M expenses, working capital and taxes. Mr. Rubin stated that the use of riders for only certain aspects of a company's revenue requirement violates the matching principle "and helps to destroy the underlying relationship between utility rates and levels of cost and investment."

In the AG's view, the Company's own historical rate of main replacement investment further suggests Rider ICR simply is not needed. For example, between 1981 and 1993, the Company averaged replacement of about 77 miles per year. Staff Cross Exhibit 20, introduced during the cross-examination of PGL witness Doerk, shows historical miles of CI/DI main replaced from 1981 through 2006. This exhibit reveals that Peoples Gas regularly replaced more than 50 miles of CI/DI main during that time period without a rider cost recovery mechanism, with the Company installing more than 100 miles of new main in 1991. Such a mechanism as Rider ICR has not been needed in the past the AG argues, and Peoples failed to show why it would be needed now.

According to the AG, the Commission's recent decision in the Nicor Gas rate case supports rejection of the Company's Rider ICR proposal. In Docket 08-0363, Nicor proposed a rider that would provide special ratemaking treatment for distribution investment above a designated base level (unlike Peoples Gas' rider which requests special rate treatment for *all* new distribution investment in the six plant accounts). Nicor defined the base level of investment based on its historical practices, as being the replacement of 15 miles of mains and 3,500 service lines per year. It also offered to cap the total annual investment above that base amount to $20 million.

Even with those restrictions, the Commission rejected the rider, stating:

> In summary, what Nicor has proven, at best, is only that Rider QIP would allow Nicor to better keep pace with the declining performance of the materials in question. It has provided us with no reason to impose the additional cost of "better keeping pace" upon ratepayers, many of whom are, as Nicor has acknowledged, facing difficult financial times. *Nicor 2008* at 170.

Like Nicor, the AG argues, Peoples Gas failed to explain why ratepayers should be saddled with paying monthly surcharges to finance projected infrastructure investments. Instead, Peoples Gas has "bet the house", on its reading of the Commission's last rate Order, that if it presented a cost benefit analysis that showed that acceleration produced positive net savings, its Rider ICR proposal would be approved. The Commission should reject that gamble, the AG argues, as the Company failed to provide even a prima facie case for rider approval.

<u>Peoples Gas Has Not and Will Not Commit to an Acceleration Plan in this Case.</u>

While Peoples Gas presented a cost benefit analysis of acceleration of CI/DI main replacement as support for its proposed Rider ICR, the Company has made clear throughout this case that it is *not* seeking approval by the Commission in this case of any accelerated main replacement plan. Mr. Schott specifically stated as such during cross-examination, and also insisted that Peoples would not commit to any certain start date on acceleration and would maintain control over the schedule of acceleration. Mr. Doerk, who oversees main replacement for the Company, concurred.

The AG observes the Company's position is that the current main replacement program has been managed appropriately. Indeed, the Company asserted in testimony that the current main replacement schedule provides safe, reliable natural gas distribution service. The notion that Peoples Gas is unwilling to formally commit to a specific plan or schedule for Commission approval is of concern to the AG.

<u>Mr. Marano's Cost Benefit Analysis Should Not Form the Basis for Approval of Either a Specific Accelerated Main Replacement Deadline or Rider ICR.</u>

The AG observes that Mr. Salvatore Marano, who conducted a cost benefit analysis as support for its proposed Rider ICR, examined three different timing scenarios for acceleration: 2025, 2030 and 2035, and concluded that a 2030 completion date would be the "most practical and economical" of the three choices. Mr. Marano then compared that replacement time frame with the current schedule, which would complete infrastructure replacement of Peoples Gas' CI/DI main system in about 49 years.

Mr. Marano stated that his cost/benefit analysis concluded that "there is a net benefit from the accelerated investment in cast iron and ductile iron main replacement for PGL, based on the assumptions in our analysis and the estimates of certain key parameters provided by PGL." His analysis did not make any assumptions as to whether revenues to help finance the project came from base rate revenue increases or Rider ICR.

The critical elements in this analysis, the AG contends, relate to the assumptions made by Mr. Marano in his evaluation. First, he assumed that inflation would grow by 1.8 percent each year for the next 49 years (the amount of time remaining in the current main replacement program). Second, he assumed that wages would increase each year for the next 49 years by twice the rate of inflation, or four percent. Based on those assumptions, Mr. Marano then concluded that the Company would save $432 million in construction costs over the 49–year period that encompasses the current acceleration rate. Of course, the AG argues, any variation in those assumptions will produce different results, as Mr. Marano admitted.

Mr. Marano's assumptions trigger significant differences in assumed construction costs between his preferred 2030 scenario and the current 2059 completion date. According to the AG, this is because of Mr. Marano's assumption that materials costs will increase at 1.7 times the rate of inflation and that labor costs will increase at 2.2 times the rate of inflation occur under the Company's modeling each and every year.

It was noted by Mr. Rubin, the AG points out, that the construction expenditure savings to which Mr. Marano refers at page 12 of his rebuttal testimony exist solely because of the underlying assumptions about materials and labor escalation costs. So, the longer an investment is delayed, the higher the cost will be under Mr. Marano's analysis, even after inflation (or the time-value of money) is factored out of the equation, as it is in PGL Ex. SDM-1.18.

Putting aside the appropriateness of the assumptions used in the cost benefit analysis, what the AG finds most striking and troubling about the Marano recommendation is that Peoples Gas itself cannot explain how such a plan could be accomplished given the drastically reduced rate of main replacement forecasted for 2009 and 2010. As detailed by PGL witness Edward Doerk, the Company has gone from an average annual replacement rate of 45 miles in 2008, considered typical for the Company, to a 20-mile average for 2009 and a 10-mile estimate for 2010. Mr. Marano testified that he rejected adoption of a 2025 completion date because "replacing 154 miles of main per year is more than three times the current replacement rate and deemed not practical" in his opinion. Indeed, Mr. Marano's direct testimony stated that his preferred acceleration plan would require the then replacement rate of 45 miles-per-year to more than double.

Adoption of Mr. Marano's 2030 completion date, the AG contends would require Peoples Gas to step up main replacement from the forecasted 10 miles per year to 114 miles per year, or *more than 11 times* the amount replaced in forecasted 2010. Mr. Marano testified that a five-year ramp up would be incorporated into a 2030 completion plan. He confirmed during cross-examination, however, that the Company's updated forecast of main replacement was not incorporated into either his overall cost benefit analysis or the reference to a five-year ramp up. Mr. Marano admitted that he "didn't look at, per se, the financial, the business aspects" of how a necessary ramp up would occur. He admitted, too, that he did not conduct any kind of an analysis of the revenue requirement effects of Commission adoption of a 2030 main replacement deadline.

According to the AG, the change in the Company's forecasted main replacement numbers for 2009 and 2010 would not only impact the practical task of completing main replacement by 2035. Mr. Marano himself admitted that these changes in the rate of main replacement affect the bottom line numbers produced in his cost benefit analysis.

The AG notes other problems with the Marano analysis. First, Mr. Marano's overall conclusion that a 2030 completion date would result in approximately $158 million in construction cost savings and $248 million in future O&M cost savings is flawed. His analysis did *not* consider the cost of capital or the depreciation of that capital in his comparison of a 2030 completion date with the existing 2059 date, both of which "are critically important to any comparison of different investment options."

AG/CUB witness Rubin noted that Mr. Marano's analysis treated every dollar expended, whether for capital or operating expenditures, as being equivalent, an assumption that Mr. Rubin explained was critically flawed because it fails to recognize the difference in terms of dollars paid by customers over time. As Mr. Rubin explained, Mr. Marano's cost benefit analysis fails to take into account the revenue requirement effect of capitalizing O&M expenses associated with the infrastructure replacement that Rider ICR incorporates within its authorized surcharge assessment.

For example, Mr. Marano observed that $159.7 million in capitalized O&M to be paid under Rider ICR is much less than the O&M expense savings of $244 million that the Company would realize if it embarked on a 2030 acceleration completion date. However, Mr. Marano failed to acknowledge that using Peoples Gas' assumptions about the cost of capital and depreciation rate on this investment, customers would be required to pay $228.4 million for these capitalized costs from 2011 through 2029, as shown on AG/CUB Ex. 6.01. Moreover, at the end of 2029, there still would be more than $135 million in capitalized costs on Peoples Gas' books (i.e. undepreciated investment). This amount, Mr. Rubin explained, would continue to earn a return and incur depreciation expense for many years into the future.

The AG asserts that Mr. Rubin's own comparison of the Company's annual estimate of cost savings under a 2030 acceleration end date with the revenue requirement for the capitalized O&M costs shows that the total O&M expense savings during this period, as projected by Peoples Gas, is approximately $99.6 million. In contrast the revenue requirement associated with the capitalized O&M costs is approximately $228.4 million. According to the AG, the net effect is that customers would be required to pay an additional $128.8 million in rates over the 19-year period of the proposed accelerated replacement program. Mr. Rubin noted, too, that capitalized O&M is just one component of investment that Peoples Gas proposes to recover through Rider ICR.

Mr. Rubin also took issue with Mr. Marano's statement that "gross savings" from the accelerated replacement program would be $432 million, and that subtracting capitalized O&M from that figure would create net savings of $272.3 million, as asserted by Mr. Marano in his rebuttal testimony. Mr. Rubin explained that the $432 million in savings is construction-related savings estimated by the Company over a 49-year period, which has ratemaking consequences:

> The problem, once again, is that this fails to consider how much customers would be required to pay in rates to support this capital

> investment. (Mr. Marano's) Scenario 3 (the accelerated program) spends the entire $2.47 billion over a 19-year period. Scenario 2 (the current program) spends $2.90 billion over a 49-year period. The impact of each of these expenditure streams on revenue requirements is very different, especially when the additional $159.7 million in capitalized O&M (also spent over 19 years) is considered.

Even if Mr. Marano is correct about labor and materials costs increasing faster than the rate of inflation over the next 49 years, the AG claims that customers would not see a savings of $432 million over time on their bills as Mr. Marano asserts. As pointed out by Mr. Rubin, what customers see on their bills depends on the annual return of and return on that capital investment.

There is a big difference between the amount invested in capital in any given year and the effect that has on customers' bills (and utility company revenues). AG/CUB Exs. 6.05 and 6.06, attached to Mr. Rubin's rebuttal testimony, calculate the annual revenue requirement associated with the capital investment Mr. Marano used to develop the $432 million in construction cost savings, supplemented with the revenue requirements associated with the $159.7 million in capitalized O&M costs that Mr. Marano did not include in his cost analysis. As discussed further in part E below, these exhibits dispute Mr. Marano's assertion that customers would see a savings of $432 million on their bills over time.

In short, the AG argues, Mr. Marano's cost benefit analysis does not support a request for rider recovery of infrastructure investment. His recommendation of a 2030 end date is both impractical and unrealistic as a timeline for main replacement, given the record evidence and does not justify Commission approval of the proposed Rider ICR.

<u>Mr. Marano's Preferred Timeline for Acceleration of Main Replacement Would Cost Ratepayers Over $3 Billion More Than Peoples Gas' Existing Accelerated Program.</u>

The AG notes that Mr. Rubin evaluated the revenue requirement effect of adopting a main acceleration program that was completed by 2030 – the only witness in the case to do so. The results show that adoption of a 2030 main replacement completion date would have dire consequences on ratepayers and still require annual or biannual rate case filings even with Rider ICR.

According to the AG, the worst indictment of Mr. Marano's analysis and his preferred 2030 completion date for main replacement can be found in Mr. Rubin's unrebutted comparison of the total revenue requirement effect of Mr. Marano's preferred 2030 date and the 2059 date that exists under the current accelerated main replacement plan. AG/CUB Exhibit 6.05 shows the revenue requirements associated with Peoples Gas' current main replacement program. As explained by Mr. Rubin, the total capital-related revenue requirement (that is, pre-tax return and depreciation) associated with continuing this program through the year 2059 (the end year of the existing acceleration program) is $8.87 billion. On Exhibit 6.06, Mr. Rubin shows that the comparable figure for Mr. Marano's recommended 2030 end-date accelerated program, including the capitalized O&M that would be collected under Rider ICR, is $11.94 billion. Contrary to the assertions in Mr. Marano's testimony that customers would benefit from the Marano-calculated savings "in part through Rider ICR and in part through traditional ratemaking," the AG contends that when a proper revenue requirement analysis is performed that compares the costs customers actually would pay *and the revenue the Company actually would receive,* the Company's accelerated program is significantly more expensive to customers – by more than $3 billion – than the continuation of Peoples Gas' existing replacement program.

The AG notes that Mr. Schott did not dispute Mr. Rubin's comparison of the revenue requirements associated with the 2030 acceleration plan and the existing rate of replacement. When asked specifically about the analysis presented by Mr. Rubin, Mr. Schott indicated in his surrebuttal testimony and in cross-examination that the only calculation he took issue with was Mr. Rubin's failure to include about $3 million in rate case expense for each year of the period examined. Even when that expense amount is incorporated into the analysis ($3 million x 49 years, or $147 million), Mr. Marano's preferred 2030 date ends up costing ratepayers in excess of $3 billion more than current main replacement practice.

Mr. Schott likewise confirmed that even with Rider ICR, the Company's overall revenue requirement will increase under the Marano-recommended completion date. Mr. Schott further suggested that the Commission can expect Peoples Gas and North Shore to file for frequent rate relief through the rate case process – a pattern all the more likely given the extraordinary growth in revenue requirements that the Marano-recommended 2030 acceleration end date would demand:

> "The Company – Integrys' position with regard to its regulated utilities, including Peoples Gas and North Shore Gas, is we to expect earn our authorized return. And to the extent revenues are insufficient for us to earn that authorized return, we will file rate cases as needed."

The AG contends that the significant increase in revenue requirements triggered by a 2030 acceleration date, along with the Companies' position that "we expect to earn our authorized return," and will file rate cases as needed, are arguments against approving Rider ICR. As Mr. Rubin noted and Mr. Schott agreed, the filing of a rate case presents the Commission with an opportunity to review all of the Company's expenses and revenues. And to the extent that the test year recognizes changes in or additions to plant, the test year process also captures the efficiencies that reduce operating costs associated with new investment. Even if Peoples Gas launches an aggressive main replacement program, the need for revenue relief – with or without a rider – will trigger regular rate filings. At that time, the additional plant that the Company has invested in can be incorporated in the rate base, assuming it is used and useful and prudently incurred, and the revenue requirement will be adjusted accordingly. The record evidence shows no justification for burdening ratepayers -- and the Commission Staff obligated to review the rider filings -- with rider cost recovery of infrastructure investment.

One additional problem arises under a 2030 acceleration end date scenario – a problem unforeseen and not evaluated by Mr. Marano. As pointed out by Mr. Rubin, once the main replacement is completed in a 20-year time frame under a 2030 scenario, and given the 60- to 70- year average life of the plant that is being replaced, a substantial portion of the Peoples Gas distribution system would be failing within the same 20-year time frame, thus setting the company on a permanent track of rapidly accelerated main replacement. Instead of stretching out investment over 50 years, as the current plan does, replacement would be compressed over 20 years under the 2030 plan. Mr. Rubin explained the problem as follows:

> Once you accelerate the investment, collapse 50 year worth of investment into 20 years, as Peoples is proposing, that is going to create another accelerated investment problem 60 or 70 years into the future.

As such, the Commission, and ratepayers will be placed on a course of perennial acceleration of infrastructure replacements with a 20-year time frame for a substantial portion of the Company's infrastructure. For all of these reasons, the AG argues, adoption of Mr. Marano's preferred 2030 timeline for accelerated main replacement is both unrealistic and inequitable to ratepayers.

Illinois Law on Riders as a Cost Recovery Mechanism and Ratemaking Principles Under the Public Utilities Act Support Commission Rejection of PGL's Proposed Rider ICR.

The AG asserts that the Illinois courts have outlined specific guidelines for Commission approval of riders that limit the use of these extraordinary ratemaking mechanisms. These decisions make clear that the Commission does not have unfettered discretion to set rates through riders. Riders inherently undermine the rules against single-issue and retroactive ratemaking, and they contradict the fundamental principle that rates should be based on a comprehensive test year.

The circumstances that warrant rider treatment are narrow and limited, the AG states. And, all riders are "closely scrutinized because of the danger of single-issue ratemaking," which is "prohibited because it considers changes in isolation, thereby ignoring potentially offsetting considerations and risking understatement or overstatement of the overall revenue requirement." *City III,* 281 Ill.App.3d at 627. Illinois courts have allowed the use of riders to recover unexpected, volatile or fluctuating expenses that by their nature do not lend themselves to representative sampling in a single test year. *Citizens Util. Bd.*, 166 Ill. 2d at 138-139 (rider appropriate for recovery of "uncertain and variable expenses associated with coal-tar cleanup remediation required by federal statute); *see also A. Finkl & Sons Co. v. Ill. Commerce Comm'n*, 250 Ill. App. 3d 317, 327, 620 N.E.2d 1141 (1st Dist. 1993) ("*Finkl*") (Riders are useful in alleviating the burden imposed upon a utility in meeting *unexpected, volatile or fluctuating* expenses.) (emphasis in original); *City II*, 264 Ill. App. 3d at 405 (rider appropriate for recovery of costs that are uncertain in duration, timing or amount); *City I* (accepting rider to accommodate fluctuating wholesale rates for natural gas).

Illinois courts have permitted riders to recover such pass-through cost items as expenses or fees required by statute or ordinance to all ratepayers or a subset of customers. *See Citizens Util. Bd.,* 166 Ill.2d at 138-139*; City III*, 281 Ill. App. 3d at 627 (rider recovery of franchise fees to be charged to residents of municipalities assessing the fees did not constitute single-issue ratemaking). *See City II*, 264 Ill. App. 3d at 410 (Rider 28 allows Edison to look to those who cause costs to pay for them.)

Statutorily, the AG observes that the PUA provides only a few exceptions for utility cost recovery outside of rate case proceedings. *See, e.g.,* 220 ILCS 5/9-220(a) (2008), 220 ILCS 5/9-220.1 (2008), 220 ILCS 5/9-220.2 (authorizing surcharges for fuel, environmental remediation, and water and sewage infrastructure costs). More recently, the Legislature authorized rider recovery of energy efficiency program expenses (220 ILCS 5/8-103(e), 220 ILCS 5/8-104(e)) and incremental bad debt (220 ILCS 5/19-145).

In the AG's view, capital costs associated with an accelerated main replacement program are neither "*unexpected, volatile or fluctuating"* expenses. *Finkl*, 250 Ill. App. 3d at 327. Indeed, the AG claims that there is nothing unexpected or volatile about a capital improvement project under the Company's control. Nor is rider recovery of an accelerated main replacement expense authorized by statute. The General Assembly specifically authorized such rider treatment for water and sewer utilities infrastructure only. 220 ILCS 5/9-220.2. The expense associated with financing main gas distribution infrastructure replacement is more or less, the nuts and bolts of a gas distribution utility operation.

According to the AG, the Rider ICR proposal is nothing less than single-issue ratemaking. Instead of considering costs and earnings in the aggregate, where potential changes in one or more items of expense or revenue may be offset by increases or decreases in other such items, PGL's Rider ICR proposal considers changes in infrastructure investment in isolation, ignoring the totality of circumstances and thereby constituting illegal single-issue ratemaking. As such, Rider ICR ignores the traditional ratemaking process, which employs a balanced review of jurisdictional expenses, rate base investment, and the cost of capital and revenues at present rates during the test year.

The AG maintains that Rider ICR also violates the Commission's test year rules, the purpose of which is to prevent a utility from overstating its revenue requirement by mismatching low revenue data from one year with high expense data from a different year. *BPI I,* 136 Ill.2d at 219. The establishment of a test-year rate base, reflecting gross additions, retirements and transfers to plant-in-service, concluding with plant balances and total plant-in-service is a critical component of the calculation of each company's revenue requirement. The calculation of Peoples Gas' plant additions or capital expenditures for purposes of setting rates, therefore, is subject to test-year principles.

Rider ICR would provide expedited, piecemeal rate increases for incremental capital investment between rate case test years, in violation of the Commission's test-year rules. Rider ICR violates the Commission's and Illinois law's test-year principles by selecting only one component of the revenue requirement, in this case main and ancillary infrastructure investment, tracking changes in that revenue requirement component and then assessing rate adjustments to recognize this change. Accordingly, Rider ICR is illegal under the Commission's test-year rules.

The AG also notes that rider recovery of a return of, and on, infrastructure investments is the ratemaking equivalent of adding plant to rate base, as would occur in a rate case. Under Section 9-211 of the PUA, only utility plant that is used and useful and prudently incurred can be recovered in rates. Peoples Gas' Rider ICR proposal, if adopted, requires a finding by the Commission that the proposed distribution investment is prudent. Such a finding is not credible given the dearth of evidence to support a specific implementation plan and Mr. Marano's admission that he did not evaluate Peoples Gas CI/DI main in an effort to identify which main should be prioritized for accelerated replacement.

According to the AG, Rider ICR also raises retroactive ratemaking concerns. Section 9-201 of the PUA ensures that rates for utility service are set prospectively. The Illinois Supreme Court has held repeatedly that the PUA does not permit retroactive ratemaking; that is, once the Commission establishes rates, the PUA does not permit refunds if the established rates are too high, or surcharges if the rates are too low. *BPI I,* 136 Ill.2d at 209; *Citizens Utilities Co. v. Illinois Commerce Comm'n,* 124 Ill. 2d 195, 207; 529 N.E.2d 510 (1988).

The rule prohibiting retroactive ratemaking, the AG explains, is consistent with the prospective nature of the Commission's legislative function in ratemaking. In addition, this rule promotes stability in the ratemaking process. *Citizens Utilities Co. v. Illinois Commerce Comm'n*), 124 Ill.2d 195, 207, 529 N.E.2d 510 (1988). PGL's proposed rider ICR violates the prohibition in the PUA against retroactive ratemaking. Rider ICR would generate monthly surcharges based on a forecasted level of investment in six plant accounts for a particular 12-month period. A retroactive adjustment of customer rates would occur in an annual reconciliation proceeding. This retroactive adjustment of rates is not unlike the review ruled illegal in the aforementioned *Finkl* decision, wherein the Illinois Appellate Court specifically rejected Rider 22's adjustment of rates based on a prudency review, calling it a violation of the rule against retroactive ratemaking.

Given the absence of both specific statutory authority authorizing the adjustment of customer rates to reflect accelerated replacement of cast iron main for gas distribution utilities on a monthly basis, and Illinois case law regarding ratemaking and riders, it is clear to the AG that Peoples Gas' proposed Rider ICR is illegal. The Company's proposal fits none of the exceptions permitted under law for adopting this extraordinary ratemaking mechanism and, as such, should be rejected.

<u>The Mechanics of Rider ICR Favor PGL Shareholders Over Ratepayers.</u>

According to the AG, the practical mechanics of the Rider ICR tariff are also flawed. There is the use of forecasted investment amounts for purposes of computing monthly surcharges. As confirmed by PGL witness Grace, monthly ICR surcharges during each calendar year period are set based on an annual forecast of plant investments made by the Company in the preceding December. Monthly surcharges are *not* adjusted for such factors as work slow-downs triggered by the economy or weather that might affect the pace of acceleration. Rates under the tariff would not be reconciled until the end of the year, which places customers in the position of paying capital costs, depreciation and O&M expense for investments that may not have been made.

The AG recognizes that Peoples Gas proposed an offset of $6,000 per mile of main replaced to reflect estimated O&M expense savings. This $6,000 number, it argues, is just a projection produced by Mr. Marano's analysis. There is no guarantee in Rider ICR that all savings experienced by the Company as a result of CI/DI main replacement will be passed through to ratepayers through the rider tariff.

As noted by AG/CUB witness Rubin, too, the proposed rider also includes the recovery of incremental O&M expenses associated with the main replacement program itself, including management and labor costs. Peoples projects that the incremental O&M costs of its accelerated replacement program would be $159.7 million. Peoples Gas has 1,929 miles of cast iron and ductile iron mains that would be replaced over time. The total possible O&M savings offset under Peoples Gas' proposal is $11.6 million ($6,000 per mile x 1,929 miles = $11,574,000). Thus, while the Company proposes to automatically recover $159.7 million in new O&M expenses – plus hundreds of millions more for capital cost recovery – Rider ICR would credit customers with less than $12 million for reduced O&M expenses. This disparity highlights yet another defect in using riders to recover capital costs associated with infrastructure investment: riders fail to synchronize, unlike traditional ratemaking, all of the related changes in plant investment, expenses, expense savings and revenues that occur, and instead focus on a single factor affecting a utility's revenue requirement.

Finally, the AG argues that the 5% "cap" in Rider ICR, which establishes a ceiling on the amounts collected through the rider by multiplying 5% times the Company's base rate revenues is a "cap" that allows more revenues to be collected through the rider each time plant is added to rate base in a rate case. Mr. Rubin noted that with the magnitude of the accelerated program highlighted in Mr. Marano's testimony, the "cap" would be reached somewhere between every year and every two years for the entire length of the program. Thus, in order for the Company to continue spending money and earning a return on it, as envisioned in the Rider ICR tariff and Mr. Marano's suggested time frame, Peoples Gas would need to file rate cases every year or two to reset the base revenue amount built into the 5% cap. This phenomenon, as noted above, would then permit more revenues to be recovered under the "cap," thereby offering little if no protection of ratepayers from mounting surcharges. This tariff detail is yet another boon for shareholders, with ratepayers assuming all the risk of accelerated investment.

In sum, the AG argues Peoples Gas failed to sustain its burden of proving a need or justification for Rider ICR. Peoples Gas' presentation of a cost benefit analysis failed to justify adoption of what would be an extraordinary ratemaking mechanism.

D. CUB's Position

CUB states that it does not specifically address the operational need for an accelerated modernization program (except to note the flaws in the Company's cost-benefit analysis). Given the legal prescriptions against rider recovery, however, CUB argues that the proposed rider should be rejected.

CUB points out that it and the Attorney General (collectively, "AG/CUB") have co-sponsored the testimony of Scott Rubin, whose testimony concluded that automatic rate adjustment mechanisms like Rider ICR violate the matching principle and destroy the underlying relationship between utility rates and levels of cost and investment. Mr. Rubin articulated the regulatory construct that rate adjustment like Rider ICR should be used, if at all, only for significant expenses that are volatile and largely outside the Utility's control. Further, CUB return on equity witness, Mr. Christopher Thomas, testified that Rider ICR reduces the variability in the Company's future cash flow and their risk of non-recovery of the associated costs, and thus reduces the Company's overall risk of doing business.

CUB points to the testimony of Staff, which also made clear its position that Rider ICR should be rejected. CUB notes that although Staff opposes the rider, Staff witness Hathhorn nonetheless recommended several modifications to the tariff in the event the Commission approved the rider, in order to cure some of its more significant infirmities. Company witness Grace adopted many of Ms. Hathhorn's proposed modifications in rebuttal testimony. According to CUB, these modifications do not, however, cure the fatal legal and regulatory policy defects that necessitate denial of the Rider.

CUB concludes that Rider ICR violates the prohibition against retroactive and single-issue ratemaking, and violates the PUA requirement that all rates and other charges be just and reasonable and used and useful. Further, it is CUB's position that the Company failed to present compelling evidence to demonstrate that a rider is needed to recover costs associated with infrastructure replacement. For these reasons, CUB joins Staff and the Illinois Attorney General in recommending that the Commission reject Rider ICR, whether as originally proposed or as modified pursuant to the Company's adoption of Staff's recommendations.

<u>Rider ICR Fails to Satisfy Legal and Regulatory Criteria Justifying Special Rate Treatment</u>

CUB points to the PUA, which requires all utility rates and charges to be just and reasonable. Additionally, CUB notes that any significant addition to existing facilities or plant can only be included in a utility's rate base if the Commission determines that it is both prudent and used and useful in providing utility service to the utilities' customers. CUB states that Rider ICR allows infrastructure costs to be added to rate base before the Commission makes the determination that the plant is prudent, used and useful.

Thus, CUB argues, Rider ICR violates these provisions of the PUA by requiring customers to pay for infrastructure that has not been demonstrated to be used and useful or just and reasonable. Section 9-201(c) of the PUA further dictates that "the burden of proof to establish the justness and reasonableness of the proposed rates or other charges, classifications, contracts, practices, rules or regulations, in whole and in part, shall be upon the utility." 220 ILCS 5/9-201(c). CUB argues that the PUA provides for very limited exceptions to the prohibition against single-issue ratemaking. CUB submits that Peoples Gas has failed to meet its burden to justify exceptional rate treatment for the costs proposed to be collected in Rider ICR.

CUB emphasizes Illinois courts have upheld strict limitations to the use of rider mechanisms like Rider ICR to protect against single-issue and retroactive ratemaking, and to defend the fundamental principle that rates should be based on a comprehensive test year. Citing to extensive Illinois Supreme Court and Appellate Court precedent, CUB further notes that the Illinois law has circumscribed specific guidelines for Commission approval of riders that limit the use of these extraordinary ratemaking mechanisms to recovery of "unexpected, volatile or fluctuating expenses" that by their nature do not lend themselves to representative sampling in a single test year. *Citizens Utility Bd. v. Ill. Commerce Comm'n*, 166 Ill. 2d 111, 138-139, 651 N.E.2d 1089 (1995) (rider appropriate for recovery of "uncertain and variable" expenses associated with coal-tar cleanup remediation required by federal statute); *see also Finkl*, 250 Ill. App. 3d 317 ("Riders are useful in alleviating the burden imposed upon a utility in meeting *unexpected, volatile or fluctuating* expenses.") (emphasis in original); *City II*, 264 Ill. App. 3d at 405 (rider appropriate "for recovery of costs that are uncertain in duration, timing or amount"); *City I*, 13 Ill. 2d 607 (accepting rider to accommodate fluctuating wholesale rates for natural gas).

CUB acknowledges that Illinois courts have permitted riders to recover costs or fees required by statute or ordinance to all ratepayers or a subset of customers. *See Citizens Util. Bd.,* 166 Ill.2d at 138-139*; City III,* 281 Ill. App. 3d at 627 (rider recovery of franchise fees to be charged to residents of municipalities assessing the fees did not constitute single-issue ratemaking). *See City II*, 264 Ill. App. 3d at 410 ("Rider 28 allows Edison to look to those who cause costs to pay for them.") Additionally, CUB states that the PUA authorizes surcharges for fuel, environmental remediation, and water and sewage infrastructure costs. CUB notes that the PUA does not contain a similar infrastructure rider provision for electric or gas utilities. More recently, the Legislature authorized rider recovery of energy efficiency program expenses, and incremental bad debt, CUB avers that none of these exceptions to the rule against single-issue ratemaking applies in the instant case and therefore Rider ICR should be rejected.

CUB points out Mr. Rubin's testimony that, according to well-established ratemaking principles followed throughout the nation and in Illinois, "utility rates are set based on a synchronized examination of all aspects of the utility's cost of service and sources of revenue, as well as other considerations such as the quality of service and efficiency of management." AG/CUB Ex. 3.0 at 5. CUB names one treatise on utility regulation that discusses this synchronization, or the matching principle, as follows:

> If the utility proposes a change, particularly a major change, in the test year rate base, it is required also to consider the related changes in other costs or in revenue. Additional investments may result in efficiencies that reduce operating costs or quality improvements that will increase sales. Unless the utility shows that it has taken such matters into account, its revenue requirement is likely to be out of balance or overstated. Leonard Saul Goodman, The Process of Ratemaking (1998), vol. II, p. 735.

CUB avers that under normal circumstances, when a utility replaces an aging piece of equipment, it might increase rate base and depreciation expense, but it also could reduce maintenance expenses or produce other cost savings (such as reducing losses).

CUB asserts that Rider ICR isolates costs of infrastructure without proper consideration of savings. Peoples Gas' proposal to include savings of $6,000 per mile of main replaced is a projection produced by Mr. Marano, and CUB suggests this does not represent a complete balanced analysis, synchronizing all aspects of the Utility's cost of service, as required in a traditional test year rate proceeding.

Furthermore, CUB notes that the Commission has previously considered and rejected similar proposed infrastructure riders in the recent past. In fact, CUB points to Peoples Gas itself, which proposed a nearly identical Rider ICR in its last rate case, Docket No. 07-0242. There, CUB notes, the Commission rejected Peoples Gas' request for insufficient evidentiary support of the type it wanted to see. *Peoples 2007,* Order at 162. CUB contends that the Commission did not state that if these conditions were met it would approve an infrastructure rider – only that it "might have been easier to approve" a rider if these provisions were included in the request.

CUB further points to the most recent Nicor Gas rate case, where the Commission similarly rejected a proposal for a cast iron main replacement program – what Nicor termed Rider QIP (Qualifying Infrastructure Program). There, the Commission concluded that Nicor has "provided us with no reason to impose the additional cost of 'better keeping pace' upon ratepayers, many of whom are, as Nicor has acknowledged, facing difficult financial times." Order at 1709, Docket 08-0363 (Mar. 25, 2009).

Mr. Rubin likewise concluded that Peoples Gas has not shown it is necessary – not to mention fair to customers – to have a capital-cost recovery rider begin with the first dollar of investment as opposed to setting a base level of investment that would be treated under traditional regulatory concepts (as Nicor had proposed)." AG/CUB Ex. 3.0 at 8.

CUB claims that Rider ICR does not address or respond to issues of volatility or uncertainty or costs beyond the control of management. In fact, CUB emphasizes that the Company does not argue costs under Rider ICR are unexpected or volatile, nor could it, since these costs are well within the control of management. Instead, CUB avers that costs of financing basic infrastructure investment are the most central investment a gas utility can make, considering it is the means by which the utility is able to perform its obligation to deliver natural gas to its customers. In fact, CUB notes that Peoples Gas has had an existing CI/DI main replacement program for years, and has been able to undertake this investment - and maintain and "prudently operate" its gas distribution system - without a special rider until now. Nor does Rider ICR fit within any of the statutory or judicially-recognized exceptions allowing rider recovery of specific costs, according to CUB. In sum, CUB concludes Peoples Gas' proposed Rider ICR is deficient as a matter of law and fails to satisfy regulatory requirements for rider treatment and should therefore be rejected.

<u>The Company Has Not Substantiated a Need for Extraordinary Rate Treatment</u>

CUB points out that AG/CUB witness Scott Rubin, as well as Staff witnesses Sheena Kight-Garlisch and Peter Lazare, all agreed the Company failed to prove that Rider ICR is needed or appropriate. Particularly, CUB highlights the testimony of Staff witness Kight-Garlisch, who noted that the Company identified two other methods that allow "prompt and fair rate recovery" - traditional rate case fillings with a future test year or a deferral mechanism - both of which the Company rejected in favor of Rider ICR. Ms. Kight-Garlisch testified that the Company provided no analysis to support its need for Rider ICR to raise sufficient capital to provide adequate, efficient, reliable and safe utility service at a reasonable cost. CUB further cites to the testimony of Staff witness Lazare, who was particularly critical of Mr. Schott's assertion that Rider ICR would somehow "keep the capital costs associated with the infrastructure improvement reasonable." Mr. Lazare noted that Mr. Schott provided no specific evidence concerning what the capital costs for the program would be with and without Rider ICR. Staff Ex. 9.0 at 4. According to CUB, the Company's responses to various Staff and AG data requests confirmed this fact. For example, CUB maintains that the Company created no financial models to estimate the effects on the Company's financial position, with or without Rider ICR, if it adopted an infrastructure replacement program that ended in 2030, as recommended by PGL witness Salvatore Marano.

CUB asserts that Peoples Gas failed to show that the existence or absence of Rider ICR would affect its cost of capital, impact its capability to finance necessary improvements, or jeopardize its ability to provide safe and reliable service to its customers. In fact, Mr. Schott made clear that proposed Rider ICR is desired because of the "greater level of certainty of recovery on and of the investment in cast iron main, even more critical to keep the capital costs associated with the infrastructure improvement reasonable." PGL Ex. JFS-1.0 at 14. CUB suggests that Peoples Gas could accelerate its program, as desired, without the use of extraordinary rate treatment while maintaining the balanced test year review process. Instead, CUB avers that the Company holds the proverbial gun to the Commission's head by stating that approval of Rider ICR, among other factors, would dictate whether Peoples Gas would proceed with the accelerated program. Yet, CUB points to the Company's refusal to commit to the accelerated program, even if Rider ICR is approved by the Commission:

> **Q.** But approval of the rider, in and of itself, would not necessarily dictate the pace or, in fact, whether or not the acceleration would occur; is that correct?
>
> **A.** That's correct.

Tr. at 61. Thus, CUB argues that, if awarded Rider ICR by this Commission, Peoples Gas could refuse to implement the accelerated program, yet nonetheless begin to collect revenue for all incremental costs associated with new infrastructure investment – even if not related to the accelerated main replacement program.

<u>Rider ICR Decreases Utility Risk, Provides for Excessive Returns for the Company, and Unreasonably Increases Customer Costs</u>

AG/CUB witness Rubin concludes that the net effect on the revenue requirement associated with the capitalized O&M costs is that customer would be required to pay an additional $128.8 million in rates over the 19-year period of the proposed accelerated replacement program. CUB emphasizes that Mr. Rubin presented an unrebutted comparison of the total revenue requirement effect of Mr. Marano's preferred 2030 date and the 2059 date that exists under the current accelerated main replacement plan. AG/CUB Exhibit 6.05 shows the revenue requirements associated with Peoples Gas' current main replacement program: the total capital-related revenue requirement (that is, pre-tax return and depreciation) associated with continuing this program through the year 2059 (the end year of the existing acceleration program) is $8.87 billion. *Id.* at 5-6. On Exhibit 6.06, Mr. Rubin shows that the comparable figure for Mr. Marano's recommended 2030 end-date accelerated program, including the capitalized O&M that would be collected under Rider ICR is $11.94 billion. Thus, CUB argues, contrary to the assertions in Mr. Marano's testimony that customers would experience a net benefit from the accelerated investment program, when a proper revenue requirement analysis is performed that compares the costs customers actually would pay *and the revenue the Company actually would receive,* the Company's accelerated program is significantly *more* expensive to customers – by more than $3 billion – than is the continuation of Peoples Gas' existing replacement program.

CUB contends that the rate of return credit proposed by the Company would not protect customers from paying excessive rates. First, CUB maintains that the 5% cap built into the rider would increase the allowed dollars under Rider ICR each time rate base grows – i.e. when the utility files a rate case. Second, Mr. Rubin noted that with the magnitude of the accelerated program highlighted in Mr. Marano's testimony, the "cap" would be reached somewhere between every year and every two years for the entire length of the program. Thus, CUB argues that, in order for the Company to continue spending money and earning a return on it, as envisioned in the Rider ICR tariff and Mr. Marano's suggested time frame, Peoples Gas would need to file rate cases every year or two to reset the base revenue amount built into the 5% cap. Third, CUB argues that the rate of return credit reduces the authorized rate of return to account for infrastructure investment only when the Company is earning more than its authorized rate of return. According to CUB, the credit does not affect excess revenues due to weather or exceptional cost control. Thus, CUB stresses the Company could still earn returns in excess of its authorized rate of return.

CUB maintains that Mr. Rubin's analysis demonstrates that customers of Peoples Gas will pay significantly more under the accelerated program. Mr. Rubin's own comparison of the Company's annual estimate of cost savings under a 2030 acceleration with the revenue requirement for the capitalized O&M costs shows that the total O&M expense savings during this period, as projected by Peoples Gas, is approximately $99.6 million. In contrast, emphasizes CUB, the revenue requirement associated with the capitalized O&M costs is approximately $228.4 million. CUB avers that the net effect is that customers would be required to pay an additional $128.8 million in rates - at a minimum - over the 19-year period of the proposed accelerated replacement program. Mr. Rubin noted, too, that capitalized O&M is just one component of investment that Peoples Gas proposes to recover through Rider ICR.

Under cross-examination, notes CUB, Mr. Schott confirmed that even with Rider ICR, the Company's overall revenue requirement will increase under Mr. Marano's recommended completion date. Mr. Schott testified, too, that the adoption of Rider ICR will not protect customers from future rate increase requests:

> The Company – Integrys' position with regard to its regulated utilities, including Peoples Gas and North Shore Gas, is we to expect earn our authorized return. And to the extent revenues are insufficient for us to earn that authorized return, we will file rate cases as needed. Tr. at 63.

CUB concludes that the significant increase in revenue requirements triggered by a 2030 acceleration date, along with the Company's position that "we expect to earn our authorized return," and will file rate cases as needed, argue strongly against approving extraordinary rate recovery.

For all these reasons, CUB strongly objects to, and requests the Commission deny, Peoples Gas' proposed Rider ICR.

E. The Union's Position

In representing the employees of Peoples Gas who work on its cast iron and ductile iron ("CI/DI") mains on a daily basis, the Union believes it is uniquely positioned to comment on Peoples Gas' main replacement program and the benefits accelerating that program will bring. The Union asserts that Rider ICR, as proposed by Peoples Gas, undoubtedly will help the company accelerate the pace of its main replacement. This acceleration not only will enhance the safety of the system for our members working on the system, but create new job opportunities as well. The Union, therefore, recommends that the Commission authorize Rider ICR as proposed by Peoples Gas in the present proceeding.

Further, the Union views the Staff's recommendations to order additional consultants to micro-manage Peoples Gas in its planning and execution of its main replacement program completely inappropriate and unnecessary. The Union's members, along with Peoples Gas' management, are capable of working together to plan and implement the acceleration of the current main replacement program.

The Union has reviewed the testimony and evidence submitted during the course of this proceeding related to Rider ICR, and only one conclusion can be drawn: the acceleration of Peoples Gas' main replacement program that Rider ICR will help enable undoubtedly will generate numerous benefits for customers, for the City of Chicago and for the persons who actually must work on the mains themselves. In its view, the testimony of Salvatore Marano, an engineering expert with significant experience working with and examining natural gas distribution systems, establishes that accelerating the main replacement program will enhance the safety of Peoples Gas' distribution system, simplify its operation, reduce the potential for operator error and increase the system's reliability and reduce the costs of operating and maintaining the system. For example:

- the number and type of regulator stations will be streamlined, reducing the amount of training, inspection and maintenance necessary, and thereby reducing the potential for human error (PGL Ex. SDM-1.0 (Rev.) at 32, 44, 45);

- the higher risk cast iron and ductile iron materials will be eliminated from the system sooner, removing the potential of crews working on mains from being injured by cast iron or ductile iron failures (*Id*. at 21-23); and
- water infiltration and freezing, which can cause outages and require additional maintenance work to be performed, will be eliminated (*Id*. at 44).

These improvements to worker safety, maintenance and operation are of particular concern to the Union. And, it notes, no party has rebutted the evidence of these benefits. When combined with the evidence of other benefits Rider ICR will help bring, the Union maintains that it is clear that Rider ICR is an infrastructure investment and modernization plan that the Commission should support.

It should not be overlooked, the Union argues, that the acceleration of the main replacement program will lead to a significant increase in the number of jobs as workers -- both in positions staffed by Union members as well as in management and in outside contractors. Mr. Marano's testimony establishes that the accelerated main replacement program could not be carried out without additional personnel being hired. These positions will provide full-time employment in skilled positions. The importance of generating jobs such as these, given the state of the economy and the unemployment rate in Illinois, should not be disregarded.

The Union maintains that Rider ICR is a key component of bringing all the resources to bear on the important effort. Therefore, the Union urges the Commission to authorize Rider ICR as proposed by Peoples Gas in this proceeding.

F. Staff's Position

Rider ICR is an infrastructure cost recovery rider that Staff observes Company witness Grace, to have described as follows:

> Peoples Gas's proposed Rider ICR will recover costs associated with the replacement of cast iron and ductile iron main and connecting facilities including services, meters and regulators. It will also recover the costs of other mains, citygate stations, regulator stations and incremental operation and maintenance expenses related to the replacement program. Costs recoverable under Rider ICR will be offset by savings that are estimated to be generated by the replacement program. Peoples Gas Ex. VG-1.0 at 35.

Staff notes that Ms. Grace provided testimony about the operation of Rider ICR, and other PGL witnesses, i.e., Mr. Schott and Mr. Marano, testified in support of proposed Rider ICR. Staff asserts, however, that their testimony fails to provide adequate support to justify adoption of a rider recovery mechanism via Rider ICR.

<u>Rider Recovery Is Only Appropriate Where the Need or Justification for Rider Recovery is Adequately Supported</u>

Staff notes that the alternative methods by which rates are set by the Commission was succinctly summarized in *Ill. Power Co. v. Ill. Commerce Comm'n*, 339 Ill. App. 3d 425, 434 (1st Dist. 2003) where the Court explained that:

> The theory behind public utility regulation is that the Commission should fix rates that "might properly be supposed to result from free competition." *State Public Utilities Comm'n v. Springfield Gas & Electric Co., 291 Ill. 209, 218, 125 N.E. 891, 896 (1919)*. It is undisputed that the Commission sets rates in two ways -- by base rates or by an automatic-cost-recovery mechanism. Base rates attempt to recover a utility's costs through estimating the total revenues necessary to recover its operating costs plus a cost of investor capital using a specific formula. *Citizens Utilities Co., 124 Ill. 2d at 200-01, 124 Ill. Dec. 529, 529 N.E.2d at 512-13*. There are circumstances, however, where particular utility costs are unique enough that circumstances warrant a recovery through an automatic-cost-recovery mechanism. *Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d 111, 138, 651 N.E.2d 1089, 1102, 209 Ill. Dec. 641 (1995)*. In *City of Chicago v. Illinois Commerce Comm'n, 13 Ill. 2d 607, 150 N.E.2d 776 (1958)*, the Illinois Supreme Court highlighted the Commission's discretionary authority to allow a rate recovery for a utility's costs through a purchased-gas adjustment tariff.

Thus, Staff asserts, automatic adjustment clauses or riders are a discretionary alternative to the traditional approach of setting rates through base rates.

Staff goes back in time to the opinion in *City of Chicago v. Illinois Commerce Comm'n*, 13 Ill. 2d 607 (1958) where the Illinois Supreme Court determined, in a case of first impression, that the Commission was authorized under the PUA to approve an automatic adjustment clause in a proper case. Here, Staff observes, the court found that the Commission's authority to approve changes in rates included the power to approve provisions that affect the dollar-and-cents cost of the product sold and was not limited to approving rates stated in terms of dollars and cents. As explained by the court:

> it is clear that the statutory authority to approve rate schedules embraces more than the authority to approve rates fixed in terms of dollars and cents. The present automatic adjustment clause is a set formula by which the price of natural gas to the ultimate consumer is fixed by inserting in the formula the wholesale price of natural gas as established by the FPC. The Public Utilities Act, taken as a whole, contemplates that a rate schedule may contain provisions which will affect the dollar-and-cents cost of the product sold.

Id. at 611. The Supreme Court concluded that the PUA vested "the Commission with power to authorize an automatic adjustment clause to be filed in a rate schedule **in the proper case**." *Id*. at 614 (emphasis added).

Staff sees *City of Chicago*, to suggest that a decision to allow rider recovery must be adequately supported by the facts and circumstances of the rider under consideration. Staff further observes that in *A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993), the court noted that the Commission's approval of a rider to recover costs associated with demand-side management ("DSM") programs violated the prohibition against single-issue ratemaking by isolating one operating expense for full recovery without considering whether changes in other expenses or increased sales and income obviate the need for increased charges to consumers

> In the present case, the Commission authorized Edison to charge customers for DSM program costs without considering whether other factors offset the need for additional charges. The order violates the prohibition against single-issue ratemaking. The order thereby isolates one operating expense for full recovery without considering whether changes in other expenses or increased sales and income obviate the need for increased charges to consumers, which may result impermissibly in ratepayers facing additional charges for direct and indirect additional revenues to cover Edison's expenses and pay a return to its investors.

Staff notes that while all riders would seem to raise single-issue ratemaking concerns since they are typically used to recover specific or isolated costs, the *Finkl* court made clear that all riders are not prohibited by the rule against single-issue ratemaking. Indeed, the court recognized that "[r]iders are useful in alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses," but found that the DSM related expenses at issue were ordinary expenses that "reveal no greater potential for unexpected, volatile or fluctuating expenses which Edison cannot control, than costs incurred in estimating base ratemaking."

In this way, Staff observes, the *Finkl* opinion establishes that rider recovery is exempt from the prohibition against single issue ratemaking when there is adequate justification or need for rider recovery – such as alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses.

In *Central Ill. Light Co. v. Illinois Commerce Comm'n*, 255 Ill. App. 3d 876 (3rd Dist. 1993) ("CILCO v. ICC"), affirmed in part and reversed in part, *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111 (1995) ("CUB v. ICC"), the Third District Appellate Court and Illinois Supreme Court both upheld the Commission's approval of a rider to recover coal tar clean-up expenditures for costs associated with cleaning up environmental damage resulting from former manufactured gas plant operations. Significantly, the Third District's opinion made clear that adequate justification for rider recovery existed in rejecting arguments that the proposed rider violates the prohibitions against single-issue and retroactive ratemaking as well as the Commission's test year rules:

> In Finkl, the First District reversed an order of the Commission which had allowed Commonwealth Edison to utilize a rider to recover costs associated with demand-side management programs. Although the court found the rider in that case to violate both the prohibition against single-

> issue and retroactive ratemaking, and to contravene the Commission's "test year" requirements, we do not interpret the opinion as holding that all riders are prohibited. We note the opinion states with apparent approval that riders are useful in alleviating the burden imposed on utilities in meeting unexpected, volatile or fluctuating expenses. However, in the case before the court, the First District found the demand-side management expenses were not of such a nature as to require rider treatment, and could be readily addressed through traditional base rate proceedings.
>
> * * *
>
> In the instant case, we find no abuse of discretion on the part of the Commission in concluding that coal tar remediation costs can be recovered through a rider mechanism. The record shows these costs will vary widely from year to year depending on the type of remediation activities: from relatively small sums in the thousands (investigation costs) to the millions of dollars (actual cleanup costs). We view these costs as the type of unexpected, volatile and fluctuating costs which are more efficiently addressed through a rider mechanism. Therefore, we find the Commission had the authority to authorize a rider as the preferred method of recovery, and that under the circumstances such authorization did not constitute an abuse of discretion. *Id*. at 884-885 (emphasis added).

In the subsequent appeal to the Supreme Court, the court found that the prohibition against single-issue ratemaking does not constrain the Commission’s ability to approve direct recovery of unique costs when rider recovery is warranted:

> The prohibition against single-issue ratemaking requires that, in a general base rate proceeding, the Commission must examine all elements of the revenue requirement formula to determine the interaction and overall impact any change will have on the utility's revenue requirement, including its return on investment. **The rule does not circumscribe the Commission's ability to approve direct recovery of unique costs through a rider when circumstances warrant such treatment.** *Id*. at 137-138 (emphasis added).

The Illinois Supreme Court determined that there was adequate support for rider recovery of coal tar clean-up expenses:

> In the generic coal-tar order at issue in this appeal, the Commission stated that, given the wide variations and the difficulties in forecasting the costs of investigation and remediation activities, riders can generally be expected to provide a more accurate and efficient means of tracking costs and matching such costs with recoveries than would base rate recovery methods. Numerous witnesses testified to the uncertain and variable nature of the expenses for coal-tar clean up. We find that the proposed recovery through a rider mechanism, outside the context of a traditional

> rate proceeding, does not violate the prohibition against single-issue ratemaking. *Id*. at 138-139 (emphasis added).

In *City of Chicago v. Illinois Commerce Comm'n*, 281 Ill. App. 3d 617 (1st Dist. 1996) the court upheld the Commission's Order directing Commonwealth Edison Company ("ComEd") to remove local franchise fees from base rates for all customers and to localize recovery of those costs by a separate line item charge on the bills of customers residing in the municipality charging the fee. In response to an argument that the rider violated the prohibition against single-issue ratemaking, the court noted that "[t]he Commission has the power to authorize riders in a proper case and such authorization will not be reversed absent an abuse of discretion." The court also explained that "[s]ingle-issue ratemaking is prohibited because it considers changes in isolation, thereby ignoring potentially offsetting considerations and risking understatement or overstatement of the overall revenue requirement." The court also observed that while the Supreme Court's decision in *CUB v. ICC* found that a rider was appropriate for fluctuating costs, "it did not limit the use of a rider only to those instances where costs are unexpected, volatile or fluctuating." While acknowledging that riders must be closely scrutinized because of the danger of single-issue ratemaking, the court concluded that the danger of ignoring some items that might have an impact on the overall revenue requirement did not exist under the facts of this case:

> Here, however, that danger was not present. The proposed restructuring was exactly that--a reallocation which did not have any impact whatsoever on Edison's overall revenue requirement. The franchise fees were already included in Edison's overall rate structure; the Commission's order simply redistributed them. Because the rider here "merely facilitates direct recovery of a particular cost, without direct impact on the utility's rate of return" (*Citizens Utility Board*, 166 Ill. 2d at 138, 651 N.E.2d at 1102), it was not an abuse of discretion for the Commission to use it as the mechanism of cost recovery. *Id*. at 628-629.

While the Commission clearly has the discretionary authority under the PUA to provide for rider recovery of costs in appropriate circumstances, Staff asserts that the Company must demonstrate an adequate justification for the specific recovery proposed. Staff argues that Peoples Gas has failed to provide appropriate justification for Rider ICR.

Rider ICR Has Not Been Adequately Supported

Staff notes Company witness Schott to have testified that proposed Rider ICR is "consistent with points raised by Staff in the last rate case" and "includes many of the modifications proposed by Commission Staff in that case." Staff witness Mr. Lazare explained that Staff's primary position in the previous case was to reject the proposed rider because the need and justification for rider recovery of certain costs through Rider ICR in that Docket had not been established and was not supported by the evidence. The Staff proposed changes discussed by Mr. Schott sought to address the scenario of the Commission approving Rider ICR over its objections by mitigating the adverse impacts of a proposal that Staff considered to be fundamentally flawed. The fact that changes were proposed for that limited purpose should not be construed in any way as Staff support for Rider ICR.

Staff observes Mr. Schott to have testified that capital has become "more expensive to obtain" in the current financial crisis and that proposed Rider ICR provides greater "certainty of recovery on and of the investment in cast iron main" essential to "to keep the capital costs associated with the infrastructure improvement reasonable." Staff witness Lazare, however, considered Mr. Schott's position unsupported because there was no specific evidence concerning what the capital costs for the program would be with and without Rider ICR.

Staff notes that its witness Kight-Garlisch also considered Mr. Schott's claim that the Company needs a method to finance the expenditures for replacement of the mains "at a reasonable cost with prompt and fair rate recovery", such as with Rider ICR. Ms. Kight-Garlisch observed that Rider ICR is not the only method for "prompt and fair rate recovery" to finance an accelerated main replacement program, and that the Company rejected the possibility of relying on traditional rate case fillings with a future test year or a deferral mechanism. Staff sought support for Mr. Schott's claims. "However, the Company has provided no analysis to support its need for a Rider ICR to raise sufficient capital to provide adequate, efficient, reliable and safe utility service at a reasonable cost." *Id.*; *See also* ICC Staff Ex. 8.0, Attachment B at 2-7. Indeed, the response to each request for analyses, research, projections or models supporting the Company's claim was that no such analyses, research, projections or models were created or available. *Id.* As such, Staff argues, the record does not support the Company's claim and cannot support the request for approval of Rider ICR.

Staff does not view the testimony of Company witness Marano as supporting the adoption of a rider to collect infrastructure costs. Mr. Marano only focuses on the need for an accelerated program to replace the current network of cast iron and ductile iron mains and how that can best be accomplished. He does not, Staff points out, discuss why a rider mechanism is needed to recover the associated costs. Mr. Marano is clear on this matter, testifying as follows:

> My testimony will provide my opinion and support for the accelerated replacement of PGL's gas mains and services infrastructure, based on the need for reduction of future risk to the public, the public good created by a modern asset-based gas distribution system and the economic advantages of an accelerated program. Peoples Gas Ex. SDM-1.0 at 3.

Mr. Marano states the "analysis of regulatory mechanisms to allow companies to both recover their costs of system modernization as well as to flow reduced system costs back to customers" is presented by Company witnesses Schott and Grace.

Staff contends that the need for an accelerated infrastructure replacement program and the cost recovery mechanism for such a program are two different issues. One issue concerns whether the program is needed. If the answer is yes, the second issue concerns how the program should be funded. Mr. Marano's testimony addresses the first issue concerning whether the accelerated program is justified. He does not, however, explain why a rider mechanism would be justified in this case over traditional recovery through base rates. Therefore, Staff submits that Mr. Marano's testimony does not provide adequate support for adoption of proposed Rider ICR. While an accelerated infrastructure replacement program is a necessary prerequisite to a rider mechanism for recovery of the costs of such a program, the mere fact that such an accelerated program is justified does not automatically support or justify rider recovery.

Mr. Lazare also pointed out that the Company seeks funding for an accelerated replacement program that has yet to be developed. The testimony of Company witness Marano focused on why an accelerated replacement program is needed and what he believes is the preferred approach. When Staff sought to learn more about the plan earlier in the case, the Company responded that "Mr. Marano's testimony does not purport to describe an implementation plan already fully developed by PGL". In response to a different data request from Staff, the Company explicitly stated that "[a]t this point, without knowing whether Rider ICR will be approved, Peoples Gas has engaged only in preliminary discussions regarding an accelerated program implementation plan such as described in Mr. Marano's testimony." Mr. Lazare testified that it is difficult to assess the need for a recovery mechanism without knowing the Company's funding needs for that rider.

Staff asserts the Company should present its implementation plan before any extraordinary recovery mechanism is considered. Then, the Commission could assess that plan and decide whether it is sufficiently well-conceived to justify the adoption of an extraordinary rider recovery mechanism. The Company did not provide a detailed explanation of how its accelerated main replacement program will be implemented until its Surrebuttal Testimony which provided insufficient time for Staff and parties to respond in this case. The record in this case does not analyze that plan or otherwise contain support for the Company's proposed Rider ICR. The lack of support for the plan leaves Rider ICR without justification. Therefore, as discussed below, Staff recommends that the plan be considered in a separate proceeding.

For all the foregoing reasons, Staff recommends that Rider ICR not be approved in this proceeding.

G. Commission Analysis And Conclusion

The Company has proposed an Infrastructure Rider that it claims supports an accelerated system modernization initiative. We begin our evaluation of Rider ICR by reviewing those portions of the testimony provided by PGL witness Marano that describe the current state of PGL's system.

<u>The Current Status of Peoples Gas' Infrastructure.</u>

Salvatore Marano, an independent engineering expert, considers PGL's system to be unique. He explains that PGL has been the sole distributor of natural gas to the people of Chicago for approximately 150 years. The Company's pioneering history as a manufactured gas system, creating gas from coal and supplying it primarily for use as lighting, has resulted in the remaining legacy low-pressure gas distribution system.

As a result of PGL's long history of providing gas service to Chicago, Mr. Marano informs, the Company has the most miles of ductile iron pipe used for natural gas distribution in the United States; the system has the second largest combined mileage of cast iron and ductile iron main ("CI/DI"), as a percent of total miles of main, of any gas operator in the United States; and, the fourth greatest combined mileage of CI/DI. He explains that both the climate and geography of Chicago are factors that can adversely affect pipe integrity, e.g. poorly drained soils, large temperature variations, and conditions favorable for frost heave, which is when soil expands and contracts due to conditions of freezing and thawing.

Mr. Marano further informs that PGL operates an integrated gas distribution network comprised of medium-pressure and low-pressure systems. The 1,848 mile medium-pressure system is approximately 47 percent of the Company's distribution network. There are 2,155 miles of low-pressure system that amount to approximately 53% of the distribution network. The low-pressure system is supplied by approximately 345 medium-pressure to low-pressure district regulator stations. Main lines transport gas from the regulator vaults to individual medium and low-pressure customers via individual service lines. In all, Mr. Marano states, PGL operates and maintains approximately 4,000 miles of medium and low-pressure gas distribution main, and 508,475 service lines.

According to Mr. Marano, PGL seeks to accelerate the replacement of its gas mains and services infrastructure and achieve modernization of its aging cast iron and ductile iron as well as its antiquated low-pressure system. While working with this antiquated system, some of which is over one hundred years old, and operating with the risk posed by a ironic/DI main system, Mr. Marano maintains that PGL has prudently managed this system and the risks it poses. He opines that PGL's performance in this area is well in line with acceptable industry measures. Nonetheless, his testimony tells us there is a need to pursue a more accelerated approach of upgrading this system to prevent or mitigate foreseeable future risk of system and asset failure.

With this background in mind, the Commission proceeds to examine all of the other record evidence that bears on the Company's proposed Rider ICR.

<u>Standards for System Modernization Proposals.</u>

A Commission Order is a powerful document. Among other things, it reveals the reasons for its actions in a particular case. As such, it informs the parties and other interested persons as to what outcomes might be reasonably expected in future cases.

The Commission rejected the Company's infrastructure rider proposal in its previous rate case on grounds of insufficient evidence. But, in doing so, the Commission recognized the necessity of providing utilities guidance as to the specific type of information it required at a minimum to evaluate system modernization proposals beyond Part 656 and Section 220.2 of the PUA.

At page 162 of the Final Order for Docket 07-0242 the Commission noted :

> It might have been easier to approve the rider had the Utilities included, or the Staff or the Intervenors' elicited, such information as: a detailed description and cost analysis of the proposed system modernization; an identification and evaluation of the range of technology options considered and analysis and justification of the proposed technology approach; a

> detailed identification and description of the functionalities of the new system, related both to system operation as well as on the customer side of the meter, as well as an identification and justification of functionalities foregone; analysis of the benefits of the system modernization, both to system operation as well as to customers; these benefits should include reductions in system costs as well as an analysis of the range and benefits of potential new products and services for customers made possible by the system modernization; an analysis of regulatory mechanisms to allow companies to both recover their costs of system modernization as well as to flow reduced system costs back to customers; and an identification and analysis of legal or regulatory barriers to the implementation of system modernization proposals. Final Order at 162.

Altogether, we set out the six standards by which the Commission will evaluate the Company's proposed Rider ICR.

The Commission set the standard and Peoples Gas claims to have relied on these standards in this proceeding. We now look to see if the Company's evidence is sufficient and we take studied account of what it shows.

Standard No. 1 - A detailed description and cost analysis of the proposed system modernization.

The record informs how the aging CI/DI mains require a higher level of risk management and generate a larger number of main leaks and how these would be replaced with polyethylene ("PE") pipe materials and, when necessary, coated cathodically protected steel, that are "state-of-the art" in gas main and service materials.

The system modernization will upgrade PGL's distribution network from the low-pressure legacy system (prone to outages from water infiltration) to a medium-pressure system that will provide customers with new functionalities and benefits.

By accelerating and replacing larger amounts of main each year, Peoples Gas can add a zonal approach to the program to allow for greater economies of scale and coordination with the City and other utilities with respect to their infrastructure projects.

A detailed cost analysis was prepared by Mr. Marano to show, as best as could be projected, what the construction costs would be for replacing the CI/DI mains at the current rate (which would have the replacement completed in the year 2059), and under a nineteen-year accelerated replacement scenario which would have Peoples Gas complete its replacement program by the year 2029.

The Marano analysis concludes that the accelerated main replacement program will cost $432 million (in 2010 dollars) less in construction costs than Peoples Gas' current main replacement program over what would be its 49-year life-span. After subtracting the incremental costs (termed "Incremental O&M" in the analysis) of program management and labor (such as meter installation work) associated with the accelerated program and that are projected to be $159.7 million, Mr. Marano projects that the net construction cost savings from accelerating the main replacement program construction would be $272.3 million.

There is testimony from Mr. Marano stating that the new distribution system would provide savings in Peoples Gas' ongoing operations and maintenance ("O&M") costs by substantially reducing the amount of leak repairs, leak surveys, leak rechecks, emergency responses, regulator station inspection and maintenance, vault survey and maintenance, lost gas and inside safety inspections. Compared to the scenario where Peoples Gas would continue its current main replacement plan, the accelerated scenario would generate a total of $244 million in O&M cost savings over that same time period.

Standard No. 2 - An identification and evaluation of the range of technology options considered, and an analysis and justification of the proposed technology approach

The evidence shows that the materials to be used in replacing PGL's aging CI/DI mains are the state-of-the art in gas main and service materials. In addition, the upgrade to a medium-pressure from a low-pressure distribution system will bring Peoples Gas current with the standard for natural gas distribution systems. The record shows that a medium-pressure system also is less costly to construct because it allows for smaller diameter pipe to be used, and can take advantage of PE pipe, which is less expensive than coated steel pipe.

Among other things, Mr. Marano explains that the Company's use of directional drilling technology reduces construction restoration costs and eliminates the need to dispose of spoil caused by open trenching. His testimony describes the options available for approaches to pipe replacement and explains why the recommended use of a zonal approach to create economies of scale that may create further cost savings as well as provide benefits to the City and other utilities via the coordination of their respective infrastructure projects.

There is also testimony explaining how its "double decking" of mains, i.e., placing mains in the parkways on each side of a street rather than a single main in the middle of the street, will create a number of specific and identifiable benefits.

Standard No. 3 - A detailed identification and description of the functionalities of the new system (related both to system operation as well as on the customer side of the meter), and, an identification and justification of the functionalities foregone.

With respect to the old low-pressure system, Peoples Gas' expert Mr. Marano states that no functionalities will be foregone when that system is replaced.

The new system, Mr. Marano states, will be simpler, more reliable and optimal in design. Over 300 medium-to-low pressure regulator stations, along with their maintenance costs, can be eliminated and replaced with 54 new high to medium pressure regulator stations with a common design that will reduce construction costs and future maintenance costs. The problem of water infiltration (common with low-pressure systems), and that can cause outages, will be eliminated. The moving of meter sets to outside the house will provide greater access and improved safety, and the new meters combined with the constant pressure provided by the modernized system will measure gas usage more accurately.

In terms of system operation and maintenance, it is shown that new regulator stations will be in the parkway, providing safe access and reduced impact on traffic. This benefits the City because it will encounter fewer regulator vaults that impede street construction. Eliminating the medium to low pressure regulator stations will reduce the amount of training, inspection and maintenance necessary for upkeep, and correspondingly reduce the potential for human error. The increased use of PE pipe will reduce the risk of leaks caused by corrosion and reduce the amount of pipe required to be leak surveyed annually.

Customers will benefit from the functionalities of a modernized system and no longer need to install costly gas boosters and safety back-check valves to provide elevated pressures for modern energy efficient appliances and back-up generators. Service lines will have excess flow valves -- unavailable with a low-pressure system -- which will reduce the potential property damage caused by a damaged service line. Emergency response personnel, e.g., the City's Fire Department, will be able to shut off gas to a building from the outside meter sets, which potentially could reduce property damage in fire and other emergency situations.

Additional beneficial functionalities were indentified by Mr. Marano and include, fewer joint leaks because PE pipe is fused and steel pipe welded; use of PE pipes will enable crews to isolate gas leaks quickly by closing an existing valve or squeezing off the pipe upstream and downstream from the leak and the moving of gas mains out of the streets and into parkways will reduce third-party excavation damage, accidental gas line cuts and increase worker safety.

> *Standard No. 4 - Analysis of the benefits of the system modernization, both to system operation as well as to customers (including reductions in system costs, and an analysis of the range and benefits of potential new products and services for customers made possible by the system modernization).*

Mr. Marano explained that Peoples Gas' aging CI/DI mains are comprised of materials that pose a risk of catastrophic failures, and that this risk to customers and to Peoples Gas' personnel is what the Company must manage. While it does a good job managing these risks, Mr. Marano makes clear that these materials ultimately will fail and need to be replaced, and that the money costs of managing this system will continue to rise as it ages. The proposed system modernization will eliminate both the risks, and the high maintenance costs required for handling older higher-risk materials.

The record evidence shows that modernizing Peoples Gas' distribution network will generate savings in Peoples Gas' O&M costs that will benefit customers. Mr. Marano's analysis projected that if Peoples Gas accelerated its main replacement program, its O&M savings would amount to $244 million between the years 2011 and 2059 because of a substantial reduction in the amount of leak repairs, leak surveys, leak rechecks, emergency responses, regulation station inspection and maintenance, vault surveys and maintenance, lost gas and inside safety inspections.

Customers would further benefit from the synergies and efficiencies in system maintenance by no longer being inconvenienced by the need to schedule inside safety inspections, suffer from water infiltration outages or the freeze-up of low-pressure risers.

A medium-pressure system upgrade will enable customers to more easily use technologies and appliances, particularly high-efficiency appliances, not compatible with the low-pressure system now in place. To operate these types of appliances and natural gas-fired back-up generators on the low-pressure system, customers are required to install and maintain electric-powered gas pressure booster systems which can cost between $20,000 and $50,000.

This upgrade would be important for facilities such as schools, hospitals and emergency services providers, which are required by Chicago code to have back-up generators installed. These facilities, if now located on the low-pressure system, need a pressure booster system installed to use a natural gas-powered generator, or else use gasoline or diesel powered versions which are less environmentally friendly and potentially dangerous.

A medium-pressure system would allow all customers to install high-efficiency appliances such as tankless water heaters, fan-assisted heaters, home generators and commercial-grade cooking appliances. Not only is the availability of such high-efficiency appliances important for the environment and energy-conservation, but helps customers save money as well. An example is a tankless water heater that is estimated to cost $265 to operate a year, as opposed to $326 for a 40-gallon gas heater or $453 for a 40-gallon electric tank.

Still another financial benefit to customers of the new medium-pressure system is that it will allow customer use of corrugated steel piping, which is more economical and will allow customers to reduce their building construction costs.

Other significant "environmental" benefits of system modernization, detailed by Mr. Marano appear of record. The elimination of Peoples Gas' CI/DI mains and their replacement with PE and protected steel pipe dramatically reduces the amount of greenhouse gas emissions from the Company's mains. Based on a study by the U.S. Environmental Protection Agency, Mr. Marano estimated that by accelerating the main replacement program, Peoples Gas could further reduce the emission of greenhouse gases by approximately 10,500 Mcf per year. Upgrading the system to medium-pressure also eliminates the need for the collection, testing and disposal of water that enters the gas distribution system.

Another important benefit of accelerating the main replacement program to the City is the creation of a substantial number of jobs, given that additional people will be needed to perform the construction work (both internal and external to the company), the meter installations and relights of service and the management of the work. When questioned at the hearing as to whether Peoples Gas could accelerate the main replacement program without hiring additional personnel, Mr. Marano testified: "Absolutely not." Tr. at 887-888.

Peoples Gas argues that the evidence demonstrates that Rider ICR would generate not only financial benefits for customers in the form of construction and O&M cost savings, but additional benefits to customers such as enhanced safety, energy conservation, increased functionalities and appliance choices and reduced environmental impacts. Peoples Gas thus concludes that the evidence in the record strongly weighs in favor of authorizing Rider ICR to help bring these benefits to customers sooner than otherwise possible.

The Commission's Initial and Partial Evaluation (Standards I – 4)

While there are additional standards and evidence for the Commission to consider, we pause at this juncture to assess those items that PGL witness Marano addressed. In reviewing all of the evidence and arguments, we are aware that parties such as the AG, CUB, Staff, the City and the Union take various positions on Mr. Marano's testimony. These we must consider.

In a number of different ways, the AG and CUB claim that Rider ICR is not needed. They contend PGL did not adhere to the Commission's standards and point out that these are minimum required showings and that PGL should have also shown that the existence or absence of Rider ICR would affect its cost of capital, impact its capability to finance necessary improvements or jeopardize its ability to provide safe and reliable service to its customers. They further attempt to undermine Mr. Marano's analysis on the costs of acceleration by presenting what they term "a revenue requirements analysis." The respective testimonies of Company witness Grace, Schott and Marano, however, dispute several particulars of this presentation on individual grounds as well as on the general proposition that it fails to account for the way that Rider ICR would actually work. We view the analysis as incomplete and lacking narrative support. Further, it does not incorporate the costs associated with the ongoing management of the risk posed by an aging system that will likely increase as the system continues to age. SDM 1.0 (Rev.) at 29. Another factor left unconsidered or accounted for in the AG and CUB analysis is Mr. Marano's testimony that if in the future, failures posing a risk to the general public were to manifest themselves, a "reactive" acceleration replacement program at that time could present costly and difficult management issues. *Id*. at 29. For the Commission this is far more than just a cost issue; it is a safety issue. While such costs are not estimated by the AG, and may be impossible to estimate, it falls on the Commission to make both these types of costs and circumstances avoidable. To this end, even AG-CUB witness Rubin recognizes that the decision on whether to implement an accelerated infrastructure program such as Rider ICR should not be based solely on costs but on factors such as safety and reliability as well. Tr. at 984.

Even as to costs and savings, the Commission observes the AG to dispute nothing about Mr. Marano's testimonial assertion that adding a zonal approach to the acceleration program would allow for economies of scale that decrease costs (and provide for better coordination with City activities and other infrastructure projects). Yet, it is evidence such as this that the Commission considers material to our decision-making.

The AG asks that we deny Rider ICR for the same reasons that we rejected another utility's proposal. But, the AG is wrong in its reading and citing of our Order in the Nicor Gas Rate Case. We rejected that infrastructure proposal for failure to follow our standards. That we took seriously and indeed settled on these standards was made clear in what the Commission wrote in its Order for Docket 08-0363. After setting out the requirements established in our 2008 PGL/NS Rate Order (and reconfirmed in this proceeding), the Commission stated that:

> In the future, we encourage parties to adhere to the evidentiary requisites set forth in one of our orders when, as here, that order is directly on point as to what proof is needed to establish a particular argument.

That is not the situation reflected here. To the contrary, Peoples Gas is providing the Commission the very type of information we require.

The AG correctly points out that Mr. Marano conducted three different timing scenarios, i.e., 2025, 2030 and 2035. Further, we observe that both the AG and CUB argue strenuously against Mr. Marano's recommended 2030 completion date, Neither the AG nor CUB support any of the other acceleration dates on record.

The AG contends that nothing on record explains how the accelerated rate of main replacement for a 2030 completion date can be accomplished given the Company's current replacement operations. This we regard as an internal working matter and we observe the record to answer the AG's concerns both in terms of what the Plan submitted with Marano's Surrebuttal Testimony shows and his clear and direct explanation that more workers will need to be hired. Indeed, this is one of the economic benefits of acceleration and the reality is that it could not be coming at a more opportune time.

Altogether, the criticisms of CUB and the AG do not address or challenge Mr. Marano's study of the Company's current system risks. Additionally, they do not dispute any of the vast and different benefits to PGL's customers, to its workers, or to the City planning personnel and crews that are shown to be provided for under the Company's proposal. The issue for both AG and CUB is whether Rider ICR is the best recovery mechanism for this program.

The City takes an altogether different position and view of the evidence. It focuses our attention on Mr. Marano's testimony stating that CI/DI mains are "higher risk materials because of their unpredictable and catastrophic failure mode." PGL Ex. 1.0 (Rev.) at 5. Iit would have the Commission note this witness's further testimony that accelerating the replacements of these "high risk materials will increase system safety and reliability and reduce the likelihood of subjecting the public and customers to the adverse effects of pipe failures." *Id*. at 6. Notably, neither the AG nor CUB dispute what the City points to and argues.

For its part, the City makes clear to us that it views the state of infrastructure in Chicago and enhancing its safe maintenance and operation as being very important. As such, the City supports PGL's proposed acceleration main replacement and Rider ICR as representing a significant effort to bolster this critical aspect of Chicago's infrastructure.

The Union represents the employees of Peoples Gas who work on its CI/DImains on a daily basis. As such, we agree that it is uniquely positioned to comment on Peoples Gas' main replacement program and the benefits accelerating that program will bring, and it recommends that the Commission authorize Rider ICR. For its part, the

Union points out that the testimony of Salvatore Marano, an engineering expert with significant experience working with and examining natural gas distribution systems, well establishes that accelerating the main replacement program will help enable the Company to enhance the safety of its distribution system, simplify its operation, reduce the potential for operator error, increase the system's reliability, reduce the costs of operating and maintaining the system, and remove the potential of crews working on mains being injured by CI/DI failures. By this account, the Union turns our head not only to the issues of safety and reliability for the general public, but also to the important worker safety benefit that Rider ICR provides.

Further, the Union would have the Commission not overlook another critical benefit brought on by the acceleration of the main replacement program, i.e., a significant increase in the number of jobs as workers both in positions staffed by Union members, as well as in management and outside contractors. The Union observes Mr. Marano's testimony to establish that the accelerated main replacement program could not be carried out without additional personnel being hired. Given the realities of the economy and the unemployment rate in Illinois, the Commission realizes that the Union's position on the importance of generating jobs in these times must be factored in on some level in our decision on Rider ICR. As we see the Union to assert, Rider ICR is the key component of bringing all the resources to bear on an important beneficial effort.

Staff does not challenge the cost-benefit analysis. Nor does Staff dispute any of Mr. Marano's testimony as it relates to the acceleration of the Company's modernization. To the contrary, Staff witness Stoller testified that he is absolutely convinced of the need for Peoples Gas to replace, and on an accelerated basis, its current CI/DI low-pressure mains. On the basis of his convictions, Staff has even developed its own proposal to address the situation of the Company's aging and outdated system.

Along with all the many other positive attributes of an accelerated main replacement presented in Mr. Marano's testimony, we observe the provision of important environmental benefits. Both this State and the City have long been at the forefront in considering the health of their citizens and in undoing or preventing damage to the environment. The testimony of Mr. Marano demonstrates for us that the Company's proposal for an accelerated program serves these interests as well.

As such, when considered in terms of the critical values of public safety and reliability and environmental good, there is simply nothing on record to counter the Company's initiative to accelerate infrastructure improvements. Indeed, we see overwhelming support for a modernization program on these very grounds.

In the final analysis, we consider Mr. Marano's statement that:

> My testimony will provide my opinion and support for the accelerated replacement of PGL's gas mains and services infrastructure based on the need for reduction of risk to the public, the public good caused by a

modern asset-based gas distribution system and the economic advantages of an accelerated program. PGL Ex. SDM-1.0 (Rev.) at 3.

The Commission concludes that Mr. Marano has provided testimony that supports this proposition and that the evidence presented fully meets and satisfies each of the initial four criteria that we established. All total, the critically material and relevant aspects of evidence presented by Mr. Marano are unrebutted, and the positions of the City, the Union, Staff and even the testimonial admission of AG/CUB witness Rubin, compel this Commission to seriously consider the Company's proposed Rider ICR. Our evaluation continues.

Remaining Standards

The Commission now begins its review of the evidence and arguments on the remaining two standards that we established.

Standard No. 5 - An analysis of regulatory mechanisms to allow companies to both recover their costs of system modernization as well as to flow reduced system costs back to customers.

We observe Staff witness Lazare to have said that even if an accelerated program can be supported, that does not necessarily make a case for the rider mechanism. Both the AG and CUB seize on this statement to argue against Rider ICR. These parties claim that the traditional ratemaking mechanism for recovering infrastructure investments of any kind is base rates. Further, they argue that the only testimony to address the alleged need for a special rider, is PGL witness James Schott's statement that, as the financial crisis has made capital more expensive to obtain, proposed Rider ICR provides the Company a greater level of certainty of recovery on and of the investment in cast iron main, that is essential to keep capital costs associated with infrastructure improvements reasonable.

For its part, the City recognizes that riders are to be used in extraordinary circumstances and that requests for the recovery costs through riders require special scrutiny. Also, the City recognizes that rider recovery is inconsistent with the traditional manner of utility regulation. Nevertheless, the City points out that replacing legacy mains as expeditiously as reasonable is an "extraordinary" situation and it supports Rider ICR.

The record shows that before proposing Rider ICR, the Company considered and rejected two other methods for recovery of costs associated with the acceleration of infrastructure expenditures, i.e., annual rate case filings and a deferral mechanism. As we understand the record, annual rate case filings were rejected by the Company due to the administrative cost and effort involved in being in a perpetual stream of rate cases. Regulatory lag further exacerbates the problems associated with annual rate case filings. Future test years rely on forecasts and given the 11-month rate case period itself, the forecast of future capital expenditures must be developed more than a year before the test period begins.

From our perspective, rate cases consume vast amounts of time, money and resources, and are not only burdensome for utilities and other parties. They also strain the limited resources of the Commission and its Staff and divert attention from other pressing matters. Ultimately too, rate case costs are consumer costs. We cannot and will not speculate on when the Company will need to come in for a rate case in the future, but, it is reasonable to believe that Rider ICR may extend that period and to that extent, it is reasonable. Notably too, we do not see Staff or any other party to say that they prefer annual rate cases.

Likewise, no party has advocated for a deferral mechanism. A deferral mechanism is based on actual expenses. Under this mechanism, costs that would be recovered currently under Rider ICR would be deferred until the next rate case and carrying cost would accrue at the Company's pre-tax cost of capital. As costs would be incurred each year, the deferral would grow each year. Depending on the length of time between rate cases, there could be significant "rate shock" in the year that the deferral is actually recovered in rates. In addition, the deferral could place a strain on the balance sheet since the deferred costs would need to be financed.

The flaws with deferral accounting are obvious. To the extent that some costs are recovered through ICR, we see less of a harmful impact on customers in terms of "rate shock," a warning put to us by the AG in arguments on other sections of this Order. Thus, the deferral mechanism is not a viable or welcome alternative to Rider ICR.

Furthermore, the record shows that Rider ICR, as proposed, is modeled on our rules at Part 656 which is a reasonable starting point for an infrastructure recovery rider such as Rider ICR. Thus, it is not a new or unusual mechanism with which the Commission is unfamiliar, and, the subject matter at hand lends itself ideally to the rider mechanism. There are several changes that the Staff proposed (and that Peoples Gas accepted) to enhance the clarity of the Rider and to improve the Commission's ability to oversee cost recovery under the rider. We will carefully review all of the Staff modifications accepted, and contested, by the Company as we continue with our evaluation of Rider ICR to ensure that the mechanism itself is well implemented.

Standard No. 6 – An identification and analysis of legal or regulatory barriers to the implementation of system modernization.

It is well-established that the Commission sets rates in two ways, i.e., by base rates and by an automatic adjustment clause, i.e. the rider mechanism. This is no different from the way rates are set in other jurisdictions. The Commission has authorized many riders over the years and not all of these have been challenged in the courts. That said, the clearest and most straight-forward expose of the relevant case law on the exercise of our rider authority presents in Staff's Initial Brief.

Staff takes us back many decades to the opinion in *City of Chicago v. Illinois Commerce Comm'n*, 13 Ill. 2d 607 (1958) where the Illinois Supreme Court determined, in a case of first impression, that the PUA vested "the Commission with power to authorize an automatic adjustment clause to be filed in a rate schedule **in the proper case**." *Id*. at 614. (Emphasis added). This Opinion, as Staff rightly points out, suggests that a decision to allow rider recovery must be adequately supported by the facts and circumstances of the rider under consideration.

In the more recent opinion in *City of Chicago v. Illinois Commerce Comm'n*, 281 Ill. App. 3d 617 (1st Dist. 1996) the Court again made clear that the Commission "has the power to authorize riders in a proper case and such authorization will not be reversed absent an abuse of discretion." Such an abuse would present itself if we were to act arbitrarily, or capriciously, or irrationally.

While the Commission confirms that it clearly has the discretionary authority under the PUA to provide for rider recovery of costs in appropriate circumstances, we need to examine, as our standards direct, if there are any legal or regulatory barriers to bar our adoption of Rider ICR.

Single-issue ratemaking

Generally, riders are challenged on the grounds of single-issue ratemaking. And we see the AG and CUB to bring this challenge here. To be sure, this claim had some validity in Peoples Gas' previous rate case, and the Commission agreed that the version of Rider ICR then at issue violated the single-issue ratemaking rule because it failed to account for savings generated by the accelerated main replacement program. However, as it is being proposed in the instant case, Rider ICR has new, different and important features. Most notably, it includes a factor for offsetting savings, generated by the accelerated program, to customers, thus preventing any over or understatement of Peoples Gas' overall revenue requirements by Rider ICR. Further, and at the suggestion of our Staff, this provision of Rider ICR has been further modified to require the re-calculation of this savings factor no less than every three years, with the Commission and other parties free to initiate proceedings to do so more frequently if necessary. In addition, there are reconciliation hearings provided for Rider ICR.

Staff notes that all riders would seem to raise single-issue ratemaking concerns since they are typically used to recover specific or isolated costs. Yet, Staff observes that the Opinion in *A. Finkl & Sons Co. v. Illinois Commerce Comm'n*, 250 Ill. App. 3d 317 (1st Dist. 1993) ("Finkl") established that rider recovery is exempt from the prohibition against single-issue ratemaking when there is adequate justification or need for rider recovery – such as alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses. In this regard, we note the AG's very own arguments to accept that variations may occur with respect to construction costs.

Staff further cites to the Illinois Supreme Court's specific pronouncements that the rule against single-issue ratemaking does not circumscribe the Commission's ability to approve direct recovery of unique costs through a rider when circumstances warrant such treatment. *Citizens Util. Bd. v. Illinois Commerce Commission*, 166 Ill. 2d 111(1995). Indeed, we find that the specific provisions of Rider ICR reconcile with the Illinois Supreme Court's recognition that "riders can generally be expected to provide a more accurate and efficient means of tracking costs and matching such costs with recoveries than would base rate recovery methods." *Id*. at 138-139 (emphasis added). We recall Mr. Scott's testimonial assertion that rider treatment provides assurance to ratepayers that they will only pay for the actual costs of infrastructure in the ground. On all these legal and factual grounds, the Commission concludes that the rule against single-issue ratemaking is not a bar to our adoption of Rider ICR, but, we observe still other challenges set out by the AG and CUB that must be addressed.

The Prohibition Against Retroactive Ratemaking.

According to the AG, Rider ICR also raises retroactive ratemaking concerns. It notes that Section 9-201 of the PUA ensures that rates for utility service are set prospectively. It points out that the Illinois Supreme Court has held repeatedly that the PUA does not permit retroactive ratemaking, i.e., once the Commission establishes rates, the PUA does not permit refunds if the established rates are too high, or surcharges if the rates are too low. The rule prohibiting retroactive ratemaking, the AG asserts, is consistent with the prospective nature of the Commission's legislative function in ratemaking and promotes stability in the ratemaking process. *Citizens Utilities Co. v. Illinois Commerce Commission*, 124 Ill.2d 195, 207, 529 N.E.2d 510 (1988).

The AG asserts that proposed Rider ICR violates the prohibition against retroactive ratemaking by generating monthly surcharges based on a forecasted level of investment in six plant accounts for a particular 12-month period. Also, it retroactively adjusts rates in an annual reconciliation proceeding. This retroactive adjustment of rates, the AG argues, is not unlike the review ruled illegal in the *Finkl* decision, where the Illinois Appellate Court specifically rejected Rider 22's adjustment of rates based on a prudency review, by calling it a violation of the rule against retroactive ratemaking.

We agree with the AG that the Court in *Finkl* accepted the argument that Rider 22 violated the prohibition against retroactive ratemaking. But, as we observed in our previous study of the matter, there is nothing in the *Finkl* opinion that provides an explanation of the Court's reasoning. There is only mention that Rider 22 provided for a prudency review of the expenses passed on to customers with the possibility of refunds if the rates were too high. The court summarily cited to *BPI v. ICC*, 136 Ill. 2d 192 (1989), for the proposition that "[o]rdering of refunds when rates are too high, and surcharges when rates are too low, violates the rule against retroactive ratemaking." Id. But, that is not the final pronouncement on the matter by the Illinois courts.

We observe again that parties in the *CILCO* case relied on *Finkl* in arguing that the riders in general violate, among other things, "the prohibition against retroactive ratemaking," and the Commission's "test year rules." But, the Court rejected such a broad reading of *Finkl* and explained its limitations by stating, in part, that:

> …we read *Finkl* as holding that the Commission abused its discretion in allowing a rider recovery mechanism under the circumstances because demand-side management costs are not of an unexpected, volatile or fluctuating nature so as to necessitate recovery through a rider. Again, we do not read *Finkl* as holding that the Commission does not have the authority to allow recovery of costs through riders. Given our view of the *Finkl* court's holding, we view the opinion's discussion of retroactive ratemaking and test year rules as dicta. 255 Ill. App. 3d at 885 (emphasis added).

The rider challenges in that case continued for review by the Illinois Supreme Court in *CUB v. ICC*. At the very outset of its discussion, the Court recognized that riders "often include a reconciliation formula, designed to match recovery with actual costs." *CUB v. ICC*, at 133 (citing *City of Chicago*, 13 Ill. 2d 607, 609 (1958)). While not addressing the retroactive ratemaking argument directly, because it was found to be waived, the Court found nothing unusual with the reconciliation procedure terms for the rider at hand. The Court observed that the reconciliation formula used to determine the amount of the rider charge includes a matching of costs incurred with the revenue realized. In the end, the Court found the Commission's approval of a rider for the recovery of coal-tar clean-up costs to be within its authority and not against the manifest weight of the evidence.

In our Order in Docket 07-0242, the Commission presented a detailed examination of what the prohibition against retroactive ratemaking really means and how it concerns rider mechanisms. We observed, after careful study, that *CILCO* is the only case that directly considers the rule against retroactive rulemaking in the "true" rider situation. We further noted that *CILCO* strictly limits the application of that doctrine by *Finkl* to the fact particulars in that decision and does not embrace it. This was well recognized and looked upon favorably by the Illinois Supreme Court in *CUB v. ICC*, both in its discussion of reconciliations generally, and in its review of the specific reconciliation mechanism that was at hand. The AG's argument does not consider any of the important case law in the field. In the end, we are not shown nor do we independently find any legal obstacle to the adoption of Rider ICR on the basis of the retroactive ratemaking doctrine.

Test Year Rules

The AG maintains that Rider ICR also violates the Commission's "test year rules," the purpose of which is to prevent a utility from overstating its revenue requirement by mismatching low revenue data from one year with high expense data from a different year. The AG maintains that the establishment of a test year rate base, reflecting gross additions, retirements and transfers to plant-in-service, concluding with plant balances and total plant-in-service is a critical component of the calculation of each Company's revenue requirement. The calculation of Peoples' plant additions or capital expenditures for purposes of setting rates, the AG contends, is subject to test-year principles.

According to the AG, Rider ICR would provide expedited, piecemeal rate increases for incremental capital investment between rate case test years, in violation of the Commission's test year rules. As such, the AG argues, Rider ICR violates the Commission's and Illinois test-year principles by selecting only one component of the revenue requirement, in this case main and ancillary infrastructure investment, tracking changes in that revenue requirement component and then assessing rate adjustments to recognize this change.

In our Order in Docket 07-0242, the Commission reviewed all of the relevant case authority when considering a similar challenge to the rider mechanism. We noted at that time that no less authority than the Illinois Supreme Court directly addressed the argument that a rider violates the Commission's own test year rules and ultimately settled the question in its opinion for *CUB v. ICC*. At the outset, the Court discussed that the test year rule set out at 83 Ill. Adm. Code 285.150, is designed to avert a mismatching of revenues and expenses that might permit a utility to inaccurately portray a higher need for rate increases. The Court looked favorably on the Commission's explanation that it was not attempting to evaluate or adjust all aspects of the utilities' base rates such that the test year filing was not a prerequisite. *Id*. In the end, the Court resolved that the test year rule seeks to avoid a problem that is simply "not present" when expenses are recovered through a rider, and, it upheld the rider.

The Court's ultimate assessment of the test year rules is applicable to the situation at hand. The Commission finds the claim of a test year violation for Rider ICR to lack merit and thus pose no legal or regulatory obstacle to its implementation.

Final Legal Analysis

In *City of Chicago v. Illinois Commerce Commission*, 13 Ill. 2d 607 (1958), the Illinois Supreme Court declared that the Commission is vested with the authority to make "pragmatic adjustments" as part of its ratemaking function. The Commission does not take its rate-setting obligations or its discretionary authority lightly. As we stated on a previous occasion, the Commission's discretion is not exercised according to its inclination, but rather on a sound judgment and reasonable assessment of the record.

We find on the entirety of this record in this case, that Rider ICR reflects a "unique" system needing improvement (Marano testimony); a pressing public concern of "extraordinary" circumstance (City); a necessary safety initiative (Staff); a worker safety benefit (Union); and, a fluctuating cost matter (AG and Marano). The City of Chicago has it right. The Commission is in the position of removing disincentives to the acceleration of system modernization and it is the record that compels us to this end. All of what we have reviewed presents such an extraordinary and unique circumstance as upon which we might properly and should pragmatically exercise our legal authority to approve Rider ICR.

Our evaluation of Rider ICR, however, is still not complete.

<u>The Rider ICR Tariff</u>

A rider will rise or fall on the features and mechanics included in the tariff language. Staff knows this and it has provided a number of concrete recommendations that are intended to ensure that there is proper regulatory oversight and that Rider ICR is implemented in the correct way. No party other than Staff has given us any specific proposals to consider.

We do see, however, CUB and the AG to claim that the monthly surcharges under the Rider ICR mechanism are not adjusted for such events as work-slowdowns that might be triggered by the economy or by weather. We believe that CUB and the AG raise a valid concern as it relates to not meeting the target 2030 acceleration plan completion date. Similarly, the AG and CUB contend that there is no guarantee that all savings resulting from CI/DI main replacement will be passed through to ratepayers through the Rider ICR tariff. According to the AG, the total possible savings offset under the tariff is $11.6 million (6,000 per mile x 1,929 miles = 11, 574,000) that Rider

ICR would credit customers. On record, however, we find Mr. Marano's testimony to be clear in explaining that customers will receive savings in part through Rider ICR and, in part, through traditional ratemaking such that the $6,000 per mile savings offset in the rider is only one piece of the savings.

Finally, the AG complains of the 5% cap in Rider ICR that establishes a ceiling on the amounts to be collected under the rider. According to its witness Rubin, the AG argues, the cap would be reached every one to two years and for the Company to continue with spending and earning a return on its investment rate cases would need to be filed accordingly. It seems clear from this argument that the AG does not actually opposes the 5% cap but that this is another way to press its opposition to accelerated main replacement.

The AG's point about the 5% cap being reached every two years has merit. Although convinced of the critical need to have an accelerated plan, the Commission remains concerned about the best way of both encouraging the Company to expedite main replacement and the relative fairness of what replacement should be considered under the accelerated plan. There are ongoing legacy costs from the 50 year plan that the Commission believes the Company has forecasted and should not be included in the accelerated program. Additionally, we find that routine operating and maintenance costs associated with those forecasted costs should also not be considered in the plan. We are of the opinion Rider ICR recovery should be reserved only for those incremental costs that exceed the legacy costs and the routine operating and maintenance costs. Therefore, the cap should not be reached as quickly as is the concern of the AG with recovery of these limited costs. We need a way, however, to differentiate these costs. The Commission finds Staff Witness Doerk's testimony on the forecast of the amount of miles of cast iron main replacement to be instructive. He opines:

> Peoples Gas currently forecasts replacing about 20 miles of cast iron main in 2009 at a total capital cost of $22 million. This compares to the original forecast of 46 miles of cast iron main replacement for a total of $50.5 million. Peoples Gas currently forecasts replacing about 10 miles of cast iron main in 2010 at a total capital cost of $11.5 million. This compares to the original forecast of 92 miles of cast iron main replacement for a total of $106 million. NS-PGL Ex. ED 2.0 at 5.

While instructive, neither this testimony, nor any of the other record evidence reflect an amount certain, in dollars or CI/DI replacement mileage, that would be above and beyond the forecasted legacy and routine maintenance costs in the accelerated program. It is the Commission's role to balance the needs of this program, which no party refutes, with the additional implementation costs which will be borne by customers. The Commission finds noteworthy the Company's desire to be proactive in updating its infrastructure. In turn, the Commission does not want to impose an additional cost on the public beyond those that are absolutely necessary, especially during these particularly harsh economic times. The Commission must be sure that any additional line item placed on a customer's bill by way of rider recovery will provide an end that is certain. We are sensitive to and again acknowledge the valid concerns of other parties that the Commission not "finance" infrastructure improvements of the Company. Recovery should be limited to those specific costs that are in line with those standards previously outlined. As such, the Commission directs the Company to meet with Staff to determine the baseline for calculating the costs that can properly be recovered under the rider as modified herein. The Company is to file a statement (and accompanying modified tariff language) with the Commission within 60 days of the approval of this Order, outlining how the Company will calculate the portion of the accelerated program that is limited to those costs determined to be beyond the agreed upon baseline.

Moreover, we observe that Staff witness Hathhorn proposed eleven recommendations concerning Rider ICR should the Commission approve the tariff. Staff points out for us that the Company accepted Staff's first, second, fourth, fifth, sixth, seventh, and eighth recommendations and reflects for us Rider ICR with the agreed-to changes.

- Section C (a) of the tariff was clarified to state: "The annual amount to be billed under Rider ICR shall not exceed the product of Annual ICR Base Rate Revenues multiplied by 5%."
- Section H of the tariff was clarified to require the Company's annual petition, testimony, and reconciliation statement be filed each year no later than March 31.
- The scope of the annual reconciliation referred to in Section H of the proposed Rider was modified to include a determination whether all costs recovered through Rider ICR were prudently incurred, just and reasonable.
- Section I-Annual Internal Audit of Rider ICR, was revised to add language to the proposed Rider ICR requiring the annual internal audit to include at least the following tests:

  (1) test that costs recovered through Rider ICR are not recovered through other approved tariffs;
  (2) test customer bills that all Rider ICR Adjustments are being properly billed to customers in the correct time periods;
  (3) test that Rider ICR revenues are properly stated; and
  (4) test that actual costs are being identified and recorded properly to be reflected in the calculation of the rates and reconciliation.

- Section B of the tariff was modified to reflect the Company's updated initial qualified infrastructure plant ("QIP") percentage for House Regulators, Account 383, of 90%.
- Factor IOM of the tariff that provides for the recovery of incremental operating and maintenance costs through Rider ICR was removed from the rider.

- Incentive compensation costs were specifically excluded for cost recovery under Rider ICR.

According to Staff, its third and tenth recommendations from Direct Testimony were withdrawn. It tells us, however, that two other recommendations of Staff witness Hathhorn remain contested. The Commission is pleased to see that the Company has accepted most of Staff's proposed modifications and we find these to be reasonable in the premises. We consider Staff's remaining recommendations out of numerical order, for reasons that will become obvious in time.

The first of the disputes concerns Staff's "eleventh" recommendation that the actual savings factor ("ActSav") be updated at least every three years. To make its point clearer, Staff explains that the Company agrees to a triennial update of the factor, but what the Company disagrees to is the proposed tariff language allowing updates "sooner if demonstrated to be necessary by the Company or any other party." In this respect, the Company argues that if the Commission wishes to review the factor more frequently, it can initiate a proceeding to do so. As Staff further explains it, the Company does not dispute the Commission's authority to review the factor more frequently, and Staff's proposed revision in tariff language provides the same opportunity to update the factor with a showing of evidence as would be necessary in a separate proceeding. Including Staff's proposed language in the tariff, Staff asserts, only makes clear that this factor may need to be updated if circumstances warrant.

Staff sets out its proposed language for Section H-Annual Reconciliation to be modified as follows:

> ActSav= Actual savings, which is determined as $6,000.00 times the actual number of miles of cast iron and ductile iron main abandoned in the reconciliation year. <u>The Company shall update ActSav no less than every three years. The first such update shall be required in the Company's third annual reconciliation proceeding, but may be updated sooner if demonstrated to be necessary by the Company or any other party.</u> Staff Exhibit 1.0 at 44 (omitting language for withdrawn tenth recommendation).

To require a separate proceeding, in Staff's view, places an unnecessary burden on both the Commission and the parties. While we understand Staff's position, we know of no way to bring a "demonstration" of necessity of any kind to the Commission without the initiation of a formal proceeding. This may be an inconvenience, but it is the only way that the Commission is able to authorize a change to what it has already established by Order. In the end, this is an important protection against arbitrary action and extends to all parties alike. For these reasons, Staff's recommendation in this instance is accepted in part and rejected in part. The phrase, "but may be updated sooner if demonstrated to be necessary by the Company or any party" will be stricken.

We further observe that the Company contests Staff's "ninth" recommendation, i.e., that no charges under Rider ICR be made until the Company's plan for its proposed accelerated infrastructure replacement program, as recommended by Staff witness Stoller, is approved by the Commission. Apparently, the Company strongly opposes Staff witness Stoller's recommendation that the Commission must first approve the

Company's accelerated infrastructure replacement plan. And for this reason, the Company opposes Staff witness Hathhorn's recommendation. This tells the Commission that we must stop at this point in our evaluation and carry our assessment of Rider ICR into the next section of this Order where we will consider Mr. Stoller's proposals.

IX. Staff Proposals And Rider ICR (Part II).

Staff, through its witness Harold Stoller, has set out three proposals on Peoples Gas' proposed acceleration of its main replacement program. These proposals would have the Commission enter an Order requiring Peoples Gas to:

1. conduct the accelerated main replacement program as outlined in Mr. Marano's testimony;
2. present a fully-developed plan for carrying out the main replacement program and obtain Commission approval of that plan in a docketed proceeding, with the plan analyzed by an independent consultant to be retained by the Commission at Peoples Gas' expense; and
3. provide an updated analysis every three years to be analyzed by an independent consultant to be retained by the Commission at Peoples Gas' expense .

Staff, the AG, Peoples Gas and the Union address each of these proposals in their respective briefs.

A. Staff's Positions

<u>Proposal No. 1 - Requiring Peoples Gas To Undertake Accelerated Program Under Section 8-503.</u>

Staff's position rests heavily on the testimony of Harold Stoller, Director of the Energy Division of the Commission Staff (in which the Commission's Pipeline Safety Program is located), who addressed Peoples Gas' proposal to commence an accelerated CI/DI main replacement program. In testimony, Staff points out, Mr. Stoller stated that he was absolutely convinced by the Direct Testimony of PGL witness Marano, of the need for Peoples Gas to replace on an accelerated basis its current CI/DI low-pressure mains with polyethylene and coated steel medium-pressure facilities. Mr. Stoller opined that what Mr. Marano had described was a gas distribution system in serious need of major renovation to keep it safe for the citizens of the City of Chicago. In Mr. Stoller's opinion, the accelerated main replacement program should be approved when a sufficiently detailed plan for that project has been reviewed by an independent consultant for the Commission.

Mr. Stoller explained that he had encountered a number of situations that he considers similar to this one. He described five situations in which either Commission Staff or an independent consultant determined that an Illinois utility had a serious problem with the condition of its electric or gas delivery system that required focused attention by the utility. In each of these cases, Mr. Stoller noted, while the Commission Staff or a consultant identified the problems, either the utility agreed, or the Commission ordered the utility to remedy the problem and hire a consultant, or directed its Staff, to monitor the progress of the utility in fulfilling that obligation.

According to Mr. Stoller, Peoples Gas' current situation presents the types of issues that were inherent in each of the five situations described in his Direct Testimony. In each of those situations, the Commission was presented with what Mr. Stoller described as a problem that it could not reasonably decline to address. Those problems, prior to being brought to the attention of the Commission,were, in one sense, "the utilities' problems," i.e., theirs to have managed and resolved in the normal course of running their business and providing adequate, reliable and safe public utility service.

In Mr. Stoller's experience, the Commission has not routinely taken upon itself responsibility to "micro-manage" utilities; that is, the Commission does not try to tell utilities how to run their businesses. When critical infrastructure problems came to the attention of the Commission, however, these were not, in Mr. Stoller's opinion, situations in which the Commission could simply acknowledge the existence of and leave the utilities to resolve. In each of the five examples Mr. Stoller identified, where it was confronted with a significant utility infrastructure deficiency problem, the Commission took proactive steps of first attempting to secure the utilities' agreement, or, when an agreement was not forthcoming, ordering the utility to resolve the problem and putting in place a process through which the Commission could monitor the utility's progress in carrying out the Commission's Order or the utility's agreement. That is the process, Staff observes, that Mr. Stoller testified should be followed in this instance.

With this issue having been brought to the attention of the Commission as part of Peoples Gas' Rider ICR filing, Mr. Stoller believes that the matter has become as much of an issue for the Commission to deal with as it once may have been an internal utility management issue for Peoples Gas to resolve. Mr. Stoller does not believe that the Commission can simply permit Peoples Gas to move on to accomplish the CI/DI main replacement program as it sees fit over time. What the Marano testimony indicates to Mr. Stoller is that Peoples Gas' approach has not worked in the past. As such, he does not believe the Commission can reasonably and responsibly rely on Peoples Gas to resolve the problem on its own going forward without in some way keeping a close eye on the situation.

Mr. Stoller testified that, in a broad sense, he views the situation regarding Peoples Gas' CI/DI main system as similar to that which might be presented if Peoples Gas were to file with the Commission a petition under Section 8-406 of the PUA (220 ILCS 5/8-406), identifying a significant project to replace a large part of its gas distribution system. Were the Commission to concur with the identified urgent need to undertake the construction program, whether for purposes of satisfying a standard of "public convenience or necessity" identified in Section 8-406, or preserving public safety as Mr. Stoller believes is the case here, it could then enter an Order under Section 8-503 of the PUA that obliged Peoples Gas to commence the construction program to repair and improve its existing plant.

Mr. Stoller testified to his belief that, no matter the source or the circumstances of the information coming to the Commission's attention, if it shows that a utility has a significant problem with its facilities that is either compromising, or might compromise in the future its ability to provide adequate, reliable and safe public utility service, the Commission has an obligation to act. For Staff, the significant difference between a typical situation where a utility has petitioned the Commission for an Order under Sections 8-406 and 8-503 of the the Act and this situation is that the current situation is one where the issue was recognized by the utility nearly thirty years ago, and now the utility is asking indirectly for authorization to undertake a twenty-year accelerated program to accomplish what its consultants told it nearly thirty years ago should be done by about twenty years from now.

In further support of its proposal, Staff asserts that Section 8-503 of the PUA explicitly authorizes the Commission to "direct" a utility to make "additions, extensions, repairs, improvements or changes" to its "existing plant, equipment, apparatus, facilities or other physical property" if they are "necessary and ought reasonably to be made" or are "necessary and should be erected, to promote the security or convenience of its employees or the public or promote the development of an effectively competitive electricity market, or in any other way to secure adequate service or facilities …." 220 ILCS 5/8-503.

Specifically, Section 8-503 provides, in relevant part, as follows:

> Whenever the Commission, after a hearing, shall find that additions, extensions, repairs or improvements to, or changes in, the existing plant, equipment, apparatus, facilities or other physical property of any public utility or of any 2 or more public utilities are necessary and ought reasonably to be made or that a new structure or structures is or are necessary and should be erected, to promote the security or convenience of its employees or the public or promote the development of an effectively competitive electricity market, or in any other way to secure adequate service or facilities, the Commission shall make and serve an order authorizing or directing that such additions, extensions, repairs, improvements or changes be made, or such structure or structures be erected at the location, in the manner and within the time specified in said order; 220 ILCS 5/8-503.

Staff submits that Section 8-503 authorizes the Commission to require Peoples Gas to undertake an accelerated CI/DI main replacement program, and it further provides authority for the Commission to adopt Mr. Stoller's recommendations to require Peoples Gas to undertake an accelerated program under the terms and conditions specified by Mr. Stoller and discussed further.

<u>Proposal No. 2 - To Require Peoples Gas To Submit Implementation Plan For Approval In Separate Docket With Analysis By Outside Expert Retained By The Commission And Paid For By Peoples Gas</u>

Staff points out that the Marano testimony identified for Mr. Stoller what he considers to be a convincing case to justify replacing the CI/DI mains in its distribution system on an expedited basis. Noting that Mr. Marano did not focus exclusively, or even primarily, on pipeline safety issues in his testimony, i.e. he also addressed the issue of a cost recovery rider, Mr. Stoller's perspective was focused exclusively on the concern for maintaining public safety and not on any other justifications that might have underlined Mr. Marano's proposal. *Id*. at 5-6. For Staff, the issue of whether there is a need to accelerate replacement of CI/DI mains is separate and distinct from the issue of the appropriate recovery mechanism.

According to Mr. Stoller, the Marano testimony led him to conclude that the Company's system is old, antiquated, and approaching the point that further aging and deterioration will eventually cause replacement to maintain public safety to become an emergency matter rather than one which can be reasonably planned and executed. Whether or not the twenty-year replacement program Mr. Marano has advocated, and with which Mr. Stoller agrees, will get the job done soon enough is only a guess. That said, Mr. Stoller believes that Peoples Gas should begin the replacement program very soon to avoid the possibility of a later emergency situation. Staff notes that Mr. Marano seems to agree on this point, given his testimony that "there is a need to pursue a more accelerated approach of upgrading the system to prevent or mitigate foreseeable future risk of system and asset failure" (Peoples Gas Ex. SDM-1.0 Rev. at 2) and "[a]ccelerating the replacement of these higher risk materials [cast and ductile iron mains] will increase system safety and reduce the likelihood of subjecting the public and customers to the adverse effects of pipe failure." *Id*. at 6. In Staff's view, Mr. Marano's most significant conclusion regarding the timing of the proposed accelerated main replacement program is that "[i]f in the future . . . failures which could pose a risk to the general public manifest themselves, a reactive acceleration of the replacement program at that time could present costly and difficult management issues as opposed to a more proactive planned approach …." *Id*. at 29.

Staff observes Mr. Marano to have suggested that the Commission would have sufficient internal resources to thoroughly evaluate any twenty-year accelerated main replacement program plan that he provided. On this point, Staff considers Mr. Marano to be mistaken. Staff explains that the Commission does not employ any experts in large industrial construction project planning. Therefore, Staff could not, bring sufficient resources and adequate professional expertise to evaluate the plan for the Commission. Similarly, Staff believes that Peoples Gas also has insufficient expertise or resources among its own personnel to develop the twenty-year program given that it is hiring the Jacobs firm to write its plan. In this regard, Staff notes Mr. Marano to have explained that the "proposed accelerated program is indeed a very large undertaking requiring careful management, planning and execution." NS-PGL Ex. SDM-3.0 at 4.

Staff is not clear if Mr. Marano's Surrebuttal filing of Peoples Gas' "plan" is meant to suggest a timeline that is to end with the Order in this Docket. For its part, Staff maintains that such an idea is entirely unrealistic even if the Commission had the necessary Staff expertise to conduct a thorough evaluation of the plan.

The record shows that Peoples Gas has itself employed the services of a professional consulting firm to work on the plans that Mr. Marano presented with his Surrebuttal Testimony and that work apparently consumed several months. In Staff's view, this rate case is not a proceeding where a massive, two-decade long infrastructure replacement program should be evaluated. This is particularly so, Staff claims, given that the plan was first provided in the Surrebuttal phase of testimony. As such, Staff recommends that the program plan be evaluated in a proceeding entirely separate and apart from this rate case.

Proposal No. 3 - To Require Peoples Gas To Periodically Submit Updates With Analysis By Outside Expert Retained By The Commission And Paid For By Peoples Gas

Staff recommends that the Commission explicitly order Peoples Gas to undertake the twenty-year program, and further require Peoples Gas to bring a plan for that twenty-year program to the Commission for approval, subject to analysis by a consultant hired by the Commission and paid for by Peoples Gas. Assuming that the program is approved, or approved as modified by the Commission, Staff would have it be ordered or secured by Peoples Gas' agreement, that the Company was to present an update on the program's progress to the Commission about every three years thereafter until the conclusion of the program. According to Staff, such updates should also be analyzed by an independent consultant hired by the Commission and at Peoples Gas' expense.

Staff notes PGL witness Marano to have observed that, in research on existing riders, "no reference to independent consultant oversight being ordered by Commissions in other states." NS-PGL Ex. SDM 2.0 at 9. Staff witness Stoller, however, did not find particularly relevant what Peoples Gas found in their research about what commissions have ordered in other states. Based on his experience in this state, and on the situations he described in his Direct Testimony, Mr. Stoller considered continuing oversight by the Commission and its Staff, based on initial and continuing expert consultant evaluation, as being absolutely essential to: (i) effective monitoring by this Commission of significant utility programs that have come to its attention; and, (ii) the successful completion of those programs. Without such oversight, Mr. Stoller is convinced that backsliding and delays of which the Commission would not be aware, or of the reasons for these events, are far too likely.

Mr. Stoller presented as an example of what can occur, without trying to assess or imply error or fault, what has occurred with Peoples Gas' own CI/DI main replacement program. Mr. Marano mentioned in his Direct Testimony the Zinder and Kiefner studies of Peoples Gas' distribution systems.

The first of those two studies, the Zinder study (Zinder Report No. ER-048 of May 22, 1981, "Zinder Report") recommended a fifty-year cast iron main replacement program. The Zinder Report indicates that it evaluated and made recommendations regarding approximately 1,679 miles of cast iron main in Peoples Gas' distribution system. The Zinder Report identified a total 8,867,000 feet of 4-inch, 6-inch, 8-inch and 12-inch cast iron pipe that should be replaced over the 50 years from 1981.

Peoples Gas' witness Mr. Doerk contends in his testimony that "more than 45% of the cast and ductile iron main system has been replaced" since 1981. Mr. Doerk might be referring to different cast iron mains than were studied by both Zinder and Mr. Marano. However, almost thirty years later after the Zinder Report, Mr. Marano is testifying about an accelerated replacement program for approximately 1,630 miles of cast iron main in Peoples Gas' distribution system. Mr. Stoller's testimony is that it is not at all clear that there has been much progress made in replacing cast iron main in Peoples Gas' distribution system in the past thirty years.

What is apparent from looking at Figure 8 on page 16 of the Kiefner and Associates report of March 1, 2007, is that Peoples Gas will need to nearly triple the average annual rate of cast and ductile main replacement that they have attained over about the last ten years to remove all CI/DI main from their distribution system in the next twenty years.

Mr. Stoller testified that it is now nearly thirty years after the Zinder Report and the Commission now has before it a recommendation from Mr. Marano for an accelerated main replacement program that would take the remaining twenty years of the fifty years originally recommended by the Zinder Report. If Peoples Gas had followed the recommendations of the Zinder Report of thirty years ago, the Commission would likely not find itself today in a situation where Mr. Marano is recommending an "accelerated" cast and ductile iron main replacement program. Mr. Stoller indicated that it is not clear from the evidence why, nearly thirty years after the fifty-year recommendation was first made, we are now faced with an accelerated twenty-year recommendation.

Mr. Stoller's position is that the Commission has no process in place today, nor sufficient resources to institute a process, for continuing oversight of the main replacement program that is in any way equivalent to what has worked for the Commission and utility customers in other circumstances and that Mr. Stoller is recommending in this situation.

The plan that Mr. Marano presented with his Surrebuttal Testimony is not the final plan with which Peoples Gas would begin the twenty-year accelerated main replacement program. Mr. Marano testified that the Commission should be able, with what he presented with his Surrebuttal Ttestimony to "track PGL's progress should the accelerated program be approved." NS-PGL Ex. SDM 2.0 at 9. However, what Mr. Marano actually provided with his Surrebuttal tTstimony was described in his Rebuttal Testimony as a "preliminary program and construction plan" (*Id*. at lines 104-105) and as an "initial phase evaluation." It is absolutely clear to Mr. Stoller that the Commission should not commit in this docketed proceeding to approval, without independent expert analysis and monitoring, of any twenty-year accelerated main replacement program based on the plan Mr. Marano provides with his Surrebuttal Testimony.

Mr. Stoller testified that the Commission should not permit itself to be found in a similar position a decade or two from now; that is, with yet another recommendation for a "hurry-up" program. It is well past high time for an accelerated main replacement program to get underway for the reasons that Mr. Marano and Mr. Stoller have both identified, and for there to be adequate oversight of the program to assure that it gets completed as required and as promised. There has been no specific expert consultant or Commission oversight of Peoples Gas' cast iron main replacement program for the last thirty years, and Mr. Stoller believes that maintaining public safety into the future demands that the experience of the past thirty years not be repeated.

Staff Conclusion Regarding Accelerated Cast and Ductile Main Replacement Program

Mr. Stoller set out a firm recommendation, based on his experience over a period of ten years with several other Illinois utilities that have experienced significant problems with deteriorated and unsatisfactory conditions of portions of their infrastructure, that the Commission should not seriously consider ordering Peoples Gas to undertake the twenty-year accelerated main replacement program without also providing for independent expert consultant evaluation prior to the Commission's approval of the plan and for continuing consultant monitoring and review of implementation of that plan.

He recommends that the Commission require the twenty-year replacement program to be undertaken and that there be expert consultant evaluation for the Commission of that plan both initially and periodically throughout its life.

It is Mr. Stoller's very firm opinion that the twenty-year program is vital for the future of public safety of Peoples Gas' distribution system, and it is also his very firm opinion that, without expert review and monitoring, the program is unlikely to be successful in replacing the antiquated infrastructure that it is focused on or being an economically sound project.

Accordingly, Staff recommends that the Commission accept all of Mr. Stoller's recommendations as described above.

B. AG's Position

Staff's Conclusion That Acceleration Is Necessary Does not Justify Adoption of a Specific Acceleration Plan in this Docket.

The AG would have it be noted that Mr. Stoller made clear at hearings that he was not necessarily endorsing the 2030 completion date highlighted in Mr. Marano's testimony. He also stated on cross-examination that he did not find any evidence in the present case that convinced him that Peoples' distribution system is not safe or not being operated safely at the present time. Tr. at 899.

For his part, Mr. Stoller conducted no cost/benefit analysis of his own, nor any sort of evaluation of the risk associated with maintaining the current infrastructure replacement plan. He also did not examine what the revenue requirement impact would be on both the Company and the ratepayers should a 2030 completion date be adopted by the Company. Mr. Stoller argued instead that the Company should be required to submit a specific implementation plan to the Commission that can be monitored on a regular basis.

In response to Mr. Stoller's request for the filing of a specific implementation plan, the AG notes that Mr. Marano submitted a document with his Surrebuttal Testimony that he described as "a guide" or "an action plan for execution." Tr. at 836. According to the AG, this sort of plan provides no detail as to when main replacement should occur, where the replacement should occur first in terms of safety and reliability and how it should be paid for in light of the substantial investment that would have to be undertaken to complete acceleration by Mr. Marano's recommended 2030 date. Tr. at

835-837. As surmised by Mr. Marano himself, "The actual execution of it still needs to be – it's going to be an evolving process over the next couple years." Tr. at 836.

Given these facts, Mr. Stoller's conclusion that main replacement acceleration is needed and the Company's Surrebuttal response to that directive, should not form the basis for approval of Mr. Marano's recommended 2030 timeline.

The Commission Should Open Another Docket to Establish A Plan For Peoples' Main Replacement That Balances Safety, Efficiency and Affordability of Rates.

The AG argues that, the instant record does not contain the information, or indeed any substantive plan, needed to provide a basis for the Commission to make findings about what acceleration rate of CI/DI main is appropriate and which, if any, main locations should be prioritized for replacement within Peoples' distribution system from public safety and reliability perspectives. Again, Mr. Marano's Surrebuttal plan does not provide that essential information. Tr. at 837. If the Commission concludes that some sort of acceleration plan should be adopted, based on Mr. Stoller's recommendation, the AG's position is that the Commission should order the Company to first study the PGL main system so that mains with a high MRI receive priority replacement treatment.

The AG states the development of an implementation plan should specify where main replacement is most needed from a safety and reliability perspective, a proposed timeline for replacement, evidence that the City of Chicago can work with and keep pace with the necessary approvals that the Company will need for replacing and installing new main, and other important details. Just as importantly, the AG believes the Company should include information about the revenue requirement effects of the plan on ratepayers and evidence that any implementation plan proposed will not trigger rate shock among Peoples' customer base.

The AG concludes it is clear that the Marano-recommended 2030 deadline is unworkable from a revenue requirements perspective. The AG notes it is also clear that Staff witness Stoller did not consider the revenue requirement effect of a 2030 deadline in his support for such an abbreviated timeframe. Finally, the AG believes any plan should provide specific detail about employment needs for both union and non-union workers under any approved implementation schedule. The AG also supports Staff's position that such a study should be independent, and subject to Commission review.

C. Peoples Gas' Position

Peoples Gas' maintains that each of Staff's recommendations as to the accelerated main replacement program should be rejected. According to the Company, Staff failed to perform any independent analysis to support its recommendations and further failed to make any showing of necessity for the actions it requests.

Ordering the Accelerated Plan

Peoples Gas notes that Mr. Stoller's recommendation that it be ordered to expedite the replacement of its CI/DI mains from the perspective of "maintaining public safety" is solely based on Mr. Marano's testimony concerning Peoples Gas' distribution system. Peoples Gas states that the Commission's authority to issue such an order would come from Section 8-503 of the PUA, which provides:

> Whenever the Commission, after hearing, shall find that … repairs or improvements to, or changes in, the existing plant, equipment, apparatus, facilities or other physical property of any public utility … are necessary and ought reasonably to be made … the Commission shall make and serve an order authorizing or directing that such … repairs, improvements or changes be made … in the manner and within the time specified in said order.220 ILCS 5/8-503.

Peoples Gas' position thus is that before the Commission may enter such an order under Section 8-503, it must find that the changes to be made -- here, the acceleration of the main replacement program -- "are necessary." *Id*.

Peoples Gas states that the only "need" testified to by Mr. Stoller to justify his recommendation is "public safety." Peoples Gas states that there is no evidence in the record that the program's immediate acceleration is necessary to prevent or eliminate a public safety concern. Peoples Gas notes that Mr. Marano testified that there is no immediate danger posed by Peoples Gas' current system and that Peoples Gas does a good job managing the risks posed by the current system. Staff witness Mr. Stoller agreed that there is no evidence in the record that Peoples Gas' system is not safe or not being operated safely at the present time. Tr. at 899.

Peoples Gas further argues that while Mr. Stoller testifies as to his "belief" that Peoples Gas cannot be relied upon to conduct its main replacement program appropriately without a Commission ordered timeline, Staff provides no evidence to support this belief. Peoples Gas demonstrates that although Mr. Stoller relies upon the recommendations of an original study conducted by Zinder Engineering, Inc. ("Zinder"), in 1981 to argue that Peoples Gas had not diligently pursued the recommended pace of main replacement, he fails to acknowledge two facts that completely undermine his conclusion.

First, Mr. Stoller fails to point out that the 2030 completion date in the 1981 Zinder report was only for specific CI/DI mains buried in clay soil, not Peoples Gas' entire CI/DI main system.

Second, Mr. Stoller fails to acknowledge that a subsequent, more in-depth study by ZEI, Inc. (a successor to Zinder) concluded that the target date for replacing the CI/DI mains should be pushed back from 2030 to 2050 based on an economic (not safety) analysis. When the recommendations from all of the studies performed on Peoples Gas' main replacement program prior to this proceeding are compared against the Company's actual performance, the evidence proves that Peoples Gas achieved a replacement rate greater than recommended by those consultants.

Peoples Gas therefore concludes that there is no evidence that acceleration of the main replacement program is necessary for public safety or that Peoples Gas cannot be relied upon to conduct its main replacement program reasonably without an order by the Commission.

Ordering Separate Docketed Proceeding and Consultants to Be Retained by Commission

Peoples Gas argues that Staff also failed to demonstrate the need to initiate a separate docketed proceeding to analyze and approve Peoples Gas' plan for implementing its accelerated main replacement program. Peoples Gas' position is that such micro-management of its operations is not the proper role for the Commission or Staff, especially in light of the fact that Staff has submitted no evidence demonstrating that Peoples Gas is incapable or unwilling to take the actions necessary to implement and execute an accelerated main replacement program on its own. This position is further supported by the Union, which notes that Staff submitted no evidence to support the need for additional consultants.

Peoples Gas submitted evidence that it engaged Mr. Marano and Jacobs Consultancy and already has prepared an initial plan of action and begun working on the type of detailed implementation plan outlined by Mr. Marano in his testimony. The Company argues that this evidence contradicts Mr. Stoller's "beliefs" and demonstrates that Peoples Gas is capable of managing, implementing and executing an accelerated main replacement program in a reasonable and prudent manner without prior approval by Commission.

Similarly, Peoples Gas' position is that Staff has made no showing that the retention of independent consultants by the Commission at Peoples Gas' expense is necessary to ensure Peoples Gas is conducting an accelerated main replacement program properly. The Commission's authority to order such a management audit or investigation is provided by Section 8-102 of thePUA. Section 8-102 requires that the Commission have reasonable grounds to believe that the investigation or audit "is necessary to assure that the utility is providing adequate, efficient, reliable, safe, and least-cost service" or that it is "likely to be cost-beneficial in enhancing the quality of service or the reasonableness of rates." *Id*. Peoples Gas argues that Staff has made neither a showing of necessity nor a showing that the benefits such consultants might provide would justify their cost. Peoples Gas points out that Staff has not even investigated what the costs of such consultants might be. Tr. at 900. Peoples Gas thus argues that, at this time, in light of the evidence of Peoples Gas' diligence and proactive efforts, and lack of evidence demonstrating their need or benefits, no justification exists at this time for imposing the cost of additional consultants on Peoples Gas.

Peoples Gas further argues that Staff's recommendations ignore the fact that if, at anytime in the future, there is evidence that Peoples Gas is mismanaging the accelerated main replacement program, moving too slowly or imprudently incurring costs, Staff or other parties have the ability to initiate proceedings to correct any such problems if and when such need arises. Rider ICR would require annual reporting and audits, and the costs recovered via the rider will be subject to annual reconciliation review. Cost savings will be required to be updated no less than every three years. Peoples Gas' position is that the reporting procedures required by Rider ICR would provide adequate opportunities for monitoring of program milestones and efficiency. *See* NS-PGL Ex. SDM 3.0 at 6. Moreover, Peoples Gas maintains the position that it has consistently represented throughout this proceeding that it is willing to provide additional reporting or updating on the program if the Commission requests or requires it. Peoples Gas also relies on the concession by Mr. Stoller during cross examination that nothing would prevent the Commission from taking action to initiate an investigation of the accelerated main replacement program or order the retention of consultants at some future time if it becomes necessary to do so. Tr. at 901-902.

Peoples Gas takes the further position that if the Commission decides to accept Staff's recommendations as to ordering the retention of consultants, such order should be made pursuant to its authority under Section 8-102 of thePUA, with the costs of the consultants borne initially by Peoples Gas to "be recovered as an expense through normal ratemaking procedures" in the Company's next rate case.

D. The Union's Position

The Union views Staff's recommendations to have the Commission order additional consultants to "micro-manage" Peoples Gas in its planning and execution of its main replacement program as being completely inappropriate and unnecessary. According to the Union, its members, along with Peoples Gas' management, are capable of working together to plan and implement the acceleration of the current main replacement program.

The Union urges the Commission to reject the recommendations made by the Staff that outside consultants be retained to review and approve Peoples Gas' plan for the accelerated main replacement program before work can proceed, as well as that such consultants be hired throughout the course of the program to review and watch over the work being done. The work currently being performed by Peoples Gas with its Union employees and outside contractors demonstrates that the Company and its employees are perfectly capable of planning and implementing a main replacement program. The evidence in the record demonstrates that Peoples Gas has exceeded the rate of main replacement previously recommended by various Company-retained experts since 1981. This has resulted in a current system that both Mr. Marano and Staff witness Mr. Stoller agree is safe and being operated safely at the present time. PGL Ex. SDM 1.0 (Rev.) at 29; Tr. at 899.

The Union points out that Staff has presented <u>no</u> evidence to show that outside consultants are necessary and no evidence indicating that Peoples Gas cannot or will not plan and implement an accelerated main replacement program in a reasonable and prudent manner. In the absence of any such evidence, the Union argues, the imposition of outside consultants to review and monitor the planning and implementation of this program would amount to unjustifiable micro-management and impose unnecessary costs on customers. Accordingly, the Union urges that Staff's recommendations in this regard be rejected.

E. Commission Analysis and Conclusions

The Commission has before it three Staff proposals all of which relate to accelerated system modernization for Peoples Gas. We note that much of the evidence that is material to Staff's position and its proposals has been relevant to our continuing evaluation of Rider ICR. We proceed here with that purpose in mind. In the process, we consider the positions on the Staff proposals as presented by Staff, the AG, the Union, and Peoples Gas.

The Case for Acceleration and Rider ICR

We are told by Staff that an accelerated modernization program for the Company is shown to be a necessity that neither the Commission nor PGL can ignore. Mr. Stoller points out that the Company's system is old, antiquated and approaching the point where further aging will become an emergency matter rather than one which can reasonably be planned and executed. It is important to Staff that the replacement program begins very soon in order to keep the system safe for the citizens of Chicago. This echoes the City's similar position of public safety in urging for our adoption of ICR.

On the other hand, we observe PGL and the AG to dispute Staff's assertions. They each point out that there is nothing to show that the Company's system is not being operated safely at the present time. We see nothing in these arguments to contradict or explain away the testimony of Mr. Stoller or PGL's expert Mr. Marano or to give confidence to the Commission for maintaining the *status quo*.

While Mr. Marano did say that PGL has prudently managed its system and the risks it poses are well in line with acceptable industry measures, his testimony further tells us that there is a need to pursue a more accelerated approach of upgrading this system to prevent or mitigate foreseeable future risk of system and asset failure. The Commission recalls well his point that costs will only rise as matters get worse or if an emergency were to erupt.

Immediate safety concerns are not what drive our concern. We expect PGL to stay attentive to the prudent operation of its system. No company wants to come before the Commission and explain away service failures or worse events. What we glean from Mr. Marano's testimony is that PGL's performance is fine to this point - but performance alone will not obliterate the risks. The Commission does not condone such a band-aid approach nor do we consider it safe for any length of time. In other words, a band-aid will not suffice in the situation where a cut is in serious need of stitching.

The Commission has general supervisory power over utilities, and as Staff points out, we have the authority to take action in situations where matters relevant to our oversight have been brought to our attention by any means. See generally, Order, Docket 08-0105 (where questions affecting a carrier's certification came to light during a routine complaint on money issues, Commission action was required). But, along with possessing jurisdictional authority over the parties and subject matter, it matters in such instances that we proceed with procedural regularity.

Staff's proposal directs our attention to Section 8-503 of the PUA. The statute provides, in relevant part, that:

> Whenever the Commission, after a hearing, shall find that additions, extensions, repairs or improvements to, or changes in, the existing plant, equipment, apparatus, facilities or other physical property of any public utility or of any 2 or more public utilities are necessary and ought

> reasonably to be made or that a new structure or structures is or are necessary and should be erected, to promote the security or convenience of its employees or the public or promote the development of an effectively competitive electricity market, or in any other way to secure adequate service or facilities, the Commission shall make and serve an order authorizing or directing that such additions, extensions, repairs, improvements or changes be made, or such structure or structures be erected at the location, in the manner and within the time specified in said order. 220 ILCS 5/8-503.

Staff submits that Section 8-503 authorizes the Commission to require Peoples Gas to undertake an accelerated CI/DI main replacement program. We agree. At the same time, however, there are obstacles to what Staff proposes.

Our study of the language in Section 8-503 makes clear that to pursue this action we would need to initiate a new formal proceeding and employ all of our traditional processes to arrive at a decision. If the outcome were such as to have the Company be required to implement an acceleration program, yet another or even a continuing series of rate cases would be likely. The prospect of a Section 8-503 proceeding is burdensome for both the Commission and the parties in terms of the expenditure of time and other resources. In addition, all of this would be occurring at a point and in a situation where Staff itself views time as of the essence.

However, that does not mean that the Commission is left powerless in the instant situation. All this time we have been reviewing the Company's Rider ICR proposal. In other words, while the Commission would surely initiate a Section 8-503 proceeding on the basis of Staff's account if it were faced with Company obstinacy or disregard, we observe that Peoples Gas is neither disinterested nor opposed to providing the outcome that Mr. Stoller considers appropriate. What this means for the Commission, however, is that Staff's persistent claim that Rider ICR is not needed, falls away.

Indeed, the subject matter of Rider ICR is virtually the same as what Staff proposes, i.e., an accelerated modernization plan. The features of the ICR mechanism provide for nearly the same quality of reporting and oversight that Staff would have us require. Indeed, Staff itself proposed a number of modifications to the tariff and these were accepted by Peoples Gas. Only one recommendation is in dispute and currently under our review here.

With Staff's testimony, accelerated system improvement has become for the Commission a matter of the public interest more so than just a Company proposal. Mr. Stoller's experience and perceptions of the instant situation inform us well, and his concerns are shared by the City, the Union and this Commission. On the other hand, the AG remains adamant in arguing against the 2030 date that Mr. Marano determined most reasonable in his analysis. We respect the AG's position of wanting to maintain the *status quo*. In the end, however, safety and reliability are simply not negotiable. Together with all of the evidence at hand, the testimony of Mr. Stoller confirms for the Commission what it should do in terms of Rider ICR.

To be clear, the ultimate question is whether the Commission approves Rider ICR to enable Peoples Gas to use its experience and experts to forge ahead with the acceleration program or whether we do nothing. The Commission finds the record in this matter compelling. Indeed, we find that we exercise our discretionary authority in the most prudent manner by approving Rider ICR.

<u>Preparation of a Plan and Approval Thereof</u>

We note that the Company acted prudently in engaging the services of Jacobs Consulting, Inc. to prepare an implementation plan. Neither Staff nor the AG say or discuss anything about the Jacobs Plan. We recognize that the Plan was only completed in time for submission with the Company's Surrebuttal Testimony. Nevertheless, it is in the record, nothing prevented any party from asking Mr. Marano either the most general or any specific questions about the plan at hearing. Even a cursory review of this document shows that important new developments were proposed for the modernization program and some appear underway.

Thus, we remain unconvinced regarding Mr. Stoller's assertion that approval of the plan be contingent on a separate docketed proceeding. Indeed, we note that Mr. Marano testified that Jacobs and PGL have examined the initial actions needed to begin the accelerated program and carry it through the ramp-up period. He further explained that the tasks outlined in the implementation program are starting up.

It is true that the kind of information that the AG claims that it would want to see is not available in the Jacob's plan. As we see it, the Jacob's Plan is in the nature of a reorganization and set-up of new processes. Yet, it is absent this type of a plan that causes most organizations to fail. In other words, the novelty of setting up a proper and effective expansion program is what presents a set of different challenges and not the execution of the tasks. The particulars of the actual work are what PGL employees are capable of, and what they do on a daily basis. There is no evidence that PGL's performance has been anything but appropriate in managing the risks in the system it has.

Indeed, the Union asks us to consider that the work currently being performed by Peoples Gas with its Union employees and outside contractors demonstrates that the Company and its employees are capable of planning and implementing a main replacement program. It further points out that Staff has presented no evidence to show that outside consultants are necessary and no evidence indicating that Peoples Gas cannot or will not plan and implement an accelerated main replacement program in a reasonable and prudent manner. We agree.

Primarily, we agree with the Company and the Union that the record does not reflect a cost-benefit justification as would be required for the Commission to order the *annual* retention of independent consultants to review Peoples Gas' plan for acceleration under such strict scrutiny, or to have the Commission review that plan in a separately docketed proceeding.

Therefore, Staff's recommendation for Rider ICR tariff language (based as it is on these aspects of Mr. Stoller's proposal), is rejected.

Monitoring Consultants

Staff's recommendation for the hiring of consultants, it explains, is driven by the need for Commission oversight. Mr. Marano tells us that the Commission will be able to clearly track PGL's expenditures against a clear set of time milestones such as types and miles of pipe replaced, meters relocated, and regulator vaults replaced and/or installed. We are made to understand that PGL will provide Staff a detailed annual report that contains information on the program's progress and both planned and completed corrective actions to mitigate any program deficiencies. We disagree with Mr. Marano, that these measures will result in the Commission having all the information necessary to conduct its oversight responsibilities in ensuring that PGL spends its funds efficiently, and that it effectively meets the goals of the accelerated program.

We understand the great importance and the critical need to have a successful acceleration plan for PGL and the ratepayers. The Commission agrees with Mr. Stoller's recommendations elicited in his testimony that some Commission oversight is needed for the successful completion of the acceleration program. He maintains that the Commission cannot, "reasonably and responsibly rely on Peoples Gas to resolve the problem on its own going forward without in some way keeping a close eye on the situation." Staff Exhibit 14.0 at 6. The Commission finds that the nature of the plan requires additional oversight to insure the successful completion of the plan in a prudent and reasonable manner. To accomplish this goal we conclude it reasonable and appropriate that, in addition to the Company's annual internal audit process, there shall be an independent audit of the plan every 5 years, beginning with the 5th year after the plan's inception, until the plan's completion in 2030. The audit shall be submitted to the Commission for its review.

Due to the many benefits that the accelerated plan provides to ratepayers, the Commission is of the opinion that time is of the essence and hereby requires completion of the acceleration plan project by 2030. Any variance from this completion date will require the Company to seek the Commission's approval.

The Company, the City and the Union filed no substantive exceptions to either the discussion or the conclusion on Rider ICR (Parts I and II). In their respective briefs on exceptions, Staff, the AG, and CUB raise essentially the same arguments against Rider ICR as were presented before.

X. Other New Riders

A. Rider UEA (Withdrawn)

1. The Record

The Utilities each proposed a Rider UEA, Uncollectible Expense Adjustment to recover gas cost-related Account 904 ("Uncollectible Accounts") expenses through a factor applied to customers' bills, rather than through base rates. NS Ex. VG 1.0 (Rev.) at 30-31; PGL Ex. VG 1.0 (Rev.) at 34. Subsequent to the filing, legislation (Public Act 96-0033) went into effect that allows gas utilities to file to recover certain Uncollectible

Accounts expenses through an automatic adjustment mechanism. 220 ILCS 5/19-145. The Utilities therefore withdrew their proposed Rider UEAs. NS-PGL Ex. VG 3.0 at 38.

2. Commission Analysis and Conclusion

The Utilities are no longer proposing Rider UEA in this proceeding, and neither Staff nor any party opposed its withdrawal. Consequently, the request to approve Rider UEA, and any proposals that were made regarding the specifics of such a rider, in this proceeding are moot.

B. Rider FCA (North Shore) (Uncontested)

1. The Record

North Shore proposed Rider FCA, Franchise Cost Adjustment. Ms. Grace explained that North Shore has franchise agreements with local governmental units so that it may use public rights of way to deliver gas to customers in those areas. Under these agreements, North Shore compensates the local government. Under Rider FCA, North Shore would annually calculate a per customer charge based on the costs imposed by each local government and applicable to the customers residing in the boundaries of the local government. Ms. Grace stated that Rider FCA would recover only costs actually incurred. Effective May 1, 2010, new base rates would go into effect for North Shore to reflect the removal of franchise costs, which would then be recoverable through the rider. NS Ex. VG 1.0 (Rev.) at 31-33. Only Staff addressed proposed Rider FCA, and it recommended that the Commission approve it. Staff Ex. 11.0 at 22.

2. Commission Analysis and Conclusion

The Commission has approved similar mechanisms for other utilities (ComEd in Docket 05-0597; Nicor Gas in Dockets 04-0779 and 08-0363 (approving a modification to an existing rider)). Staff recommended approval of the rider and no party opposed this proposal. North Shore's proposal is consistent with cost causation principles and would recover costs from customers living in the locality causing North Shore to incur the costs. The Commission finds that Rider FCA is just and reasonable and approves it. Furthermore, the Commission directs North Shore to include in its compliance filing effective base rates that include franchise costs in its test year revenue requirements and base rates that would become effective May 1, 2010, that remove franchise costs from its test year revenue requirements.

C. Rider GCA (North Shore) (Uncontested)

1. The Record

North Shore proposed Rider GCA, Governmental Agency Cost Adjustment. Ms. Grace explained that local governments may impose costs on North Shore that are incremental to those included in base rates. North Shore would annually calculate a per customer charge based on the costs imposed by each local government and applicable to the customers residing in the boundaries of the local government. According to Ms. Grace, Rider GCA would recover only costs actually incurred. NS Ex. VG 1.0 (Rev.) at

33-34. Only Staff addressed proposed Rider GCA, and it recommended that the Commission approve it. Staff Ex. 11.0 at 22.

2. Commission Analysis and Conclusion

The Commission has approved similar mechanisms for other utilities (ComEd; Nicor Gas). Staff recommended approval of the rider and no party opposed this proposal. North Shore's proposal is consistent with cost causation principles and would recover costs from customers living in the locality causing North Shore to incur the costs. The Commission finds that Rider GCA is just and reasonable and approves it.

XI. Cost of Service - Embedded Cost of Service Study

A. Uncontested Issues – Sufficiency of ECOSS for Rate Design

1. The Record

Utilities witness Hoffman Malueg testified that the ECOSSs are comprehensive and theoretically sound. She stated that the ECOSSs are a reasonable estimate of revenue requirements by customer class and support the rates that the Utilities' rate design witness developed. NS Ex. JCHM 1.0 at 37; PGL Ex. JCHM 1.0 (Rev.) at 38. Staff reviewed the Utilities' ECOSSs and concluded that each was an acceptable guidance tool for setting rates. Staff Ex. 10.0 at 13, 36.

2. Commission Analysis and Conclusions

Neither Staff nor any party contested the sufficiency of the Utilities' ECOSSs to develop rates in this proceeding. The Utilities' ECOSSs are complete, they systematically functionalize, classify and allocate costs, and they comport with the cost causation principles for preparing such studies that the Commission has approved in many other rate cases. The Commission finds that the Utilities' ECOSSs are sufficient and reasonable for developing rate designs in this proceeding.

B. Contested Issues

1. Classification of Uncollectible Account Expenses Account No. 904

This issue is addressed under rate design.

2. Sales Revenues Adjustments

a) Utilities

The Utilities opposed AG/CUB witness Effron's proposed increase to therm sales for the test year, as discussed above under the sales revenue adjustment in operating expenses and also pointed out that, if the Commission accepted it, there are several effects on the ECOSSs that Mr. Effron did not address. In particular, his failure to provide a monthly breakdown of the recommended increase to sales means that there was inadequate information to quantify the impact on the ECOSSs' revenue requirements by customer class. NS-PGL Ex. JCHM 3.0 at 6. In general, Ms. Hoffman Malueg explained that his proposal would increase the S.C. Nos. 1 and 2 class revenue requirements and decrease the revenue requirements for other service classifications. *Id*. at 8.

b) AG

The AG did not address this issues in either its Initial or Reply Brief.

c) Staff

In AG/CUB/City witness Effron's Direct Testimony he recommended that the Companies' sales forecasts in the test year be updated to reflect a significantly lower current price of gas compared to that projected at the time the sales forecasts were originally prepared. AG/CUB/City Ex. 1.0 at 14. Staff witness Harden testified that the sales forecast is a variable used in determining the distribution charge and further explained it was her understanding that if the price of gas used in the model is lower, than the sales forecast model will forecast higher customer usage which would result in lower distribution rates. However, as explained by Ms. Harden, updating the sales forecast for the price of gas would not affect the Companies' total revenue requirement nor the revenue requirement allocated to a class. Staff Ex. 24.0 at 19.

Staff witness Harden agreed with Mr. Effron that there should be an update in the sales forecasts, but did not agree with Mr. Effron's gas price. *Id*. at 20. Ms. Harden explained that Staff witness Rearden's gas price should be used instead of Mr. Effron's. While the Companies did not agree with the AG and Staff that the price of gas should be updated in the sales forecast model and indicated that there should not be an update unless all of the variables in the model were updated as well, Staff and the Companies were able to come to agreement on what the price of gas should be for certain other adjustments in particular "uncollectible expense, Company use gas, North Shore franchise gas costs, gas and storage, working capital and Peoples Gas cushion gas." Tr. at 914. Given the above, Staff's position is that the same price of gas from the Companies' Surrebuttal should also be used for Mr. Effron's sales forecast adjustment. *Id*.

d) Commission Analysis and Conclusion

For the reasons discussed above, the Commission rejected Mr. Effron's proposed adjustment to therm sales and the ECOSS issues are, therefore, moot.

XII. Rate Design

A. General Rate Design

1. Allocation of Rate Increase

a) Utilities

The Utilities' proposed rate designs are intended to accomplish the following seven objectives: (1) recover the Commission-approved revenue requirement; (2) better align revenues with underlying costs; (3) send proper price signals; (4) provide more inter- and intra-class equity; (5) maintain rate design continuity; (6) reflect gradualism; and (7) retain customers on their systems. NS Ex. VG-1.0 Rev. at 6; PGL Ex. VG-1.0 Rev. at 6.

Each of North Shore's service classifications would continue to be set at its cost of service. NS Ex. VG-1.0 Rev. at 8. Peoples Gas' S.C. No. 1 would remain under its cost of service, and S.C. No. 2 would remain over its cost of service, but each by a lesser amount than in the most recent rate cases; and S.C. Nos. 4 and 8 would continue to be set at cost. PGL Ex. VG-1.0 Rev. at 8.

The Utilities assert that their rate design proposals are consistent with their existing rate design structure. The Utilities proposed minor modifications to improve the extent to which the rates embody cost causation principles. As examples, the Utilities proposed (1) a new, third meter class for their S.C. No. 2, which will better reflect the costs for the larger usage customers expected to be served under this meter class; (2) eliminating their standby service classifications, as these customers are more logically placed on the general service classification; and (3) including usage-based eligibility criterion for each of the general service and large volume demand service classifications. These proposals are uncontested.

Coupled with the Utilities' ECOSSs, the descriptions of the Utilities' rate design, including the supporting exhibits, are detailed and specific enough that it would be straightforward to derive rates from whatever revenue requirement the Commission approves. NS-PGL Ex. VG-2.0 Rev. at 5. According to the Utilities, this is not the case for the Staff proposals. It is also not the case for the AG/CUB/City tiered rate proposal, which, in any event, only applies to S.C. No. 1.

Staff's approach takes a ratio of its proposed revenue requirement to each of the Utilities' proposed revenue requirements and applies it, uniformly, to each of the Utilities' proposed rates. This is flawed for several reasons.

First, Staff's method is not based upon costs or revenue requirements arising from an embedded cost of service study. It ignores the cost differences and cost allocations between rate classes and assumes that all Staff-proposed adjustments could be equally applied to customer, demand, and commodity related costs, although those adjustments were specific and not derived on an across the board basis. Adjustments affecting rate base and expense items are treated equally and grouped together in one revenue requirement number, without considering the type of costs affected by each adjustment. It also ignores Account specific costs and would make it impossible to render Account specific adjustments for certain rates. For example, the Utilities' witness and Staff witness Sackett agreed that it would be appropriate to remove Account 304 ("Land and Land Rights") costs from the standby service charge. Staff's rates approach would not allow that change. Also, it would not allow the Utilities to properly reflect final Account 904 costs arising from updated gas costs or any other relevant factors that the Commission may order in this proceeding. *Id*. at 9-10.

Second, Staff's method improperly adjusts: charges that the Utilities did not propose to change; charges based on specific cost-based revenue requirement components; and cost-based charges based on expenses that would be unaffected by Staff's proposed adjustments. There is no record support for these changes. For example, the Utilities did not propose to revise their Second Pulse or Rider SBO, Supplier Billing Option Service, charges, yet Staff's exhibit adjusts those charges. The Utilities proposed to set their standby service charges based on the Production and Storage revenue requirements arising from their ECOSSs, along with an Account 304 adjustment. Staff's approach is inconsistent with those facts. The Utilities proposed changes to various cost-based transportation service administrative charges. These charges are based on a specific cost study, which Staff did not contest, yet Staff's approach would change these charges. *Id*. at 10-11.

Considering individual service classifications, the general problems identified above are multiplied. For example,

- Staff supported (Staff Ex. 10.0 at 36), but did not apply, Peoples Gas' proposed equal percentage of embedded cost methodology for S.C. Nos. 1 and 2. Instead, Staff applied its uniform adjustment to the embedded customer charge (although stating that the adjustment was to the allocated customer charge).
- Staff did not accommodate the sales adjustment proposed by AG/CUB witness Effron, which Staff supports in principle (Staff Ex. 24.0 at 20), that would shift costs caused by additional S.C. Nos. 1 and 2 sales quantities to S.C. Nos. 1 and 2, respectively.
- Despite Staff's lower proposed revenue requirement, Staff's method would result, without explanation or support, in a proposed S.C. No. 2 meter class 3 customer charge that is 78% higher than Peoples Gas' proposal.
- Staff's proposed S.C. Nos. 1 and 2 rates would result in higher distribution charges arising from Staff's proposed lower customer charges. The testimony included no bill impacts for this change.
- North Shore's S.C. No. 3 and Peoples Gas' S.C. No. 4 are both set at cost based upon their ECOSSs. Uniform rate adjustments do not take that into consideration and could result in these service classifications being either above or below cost, with the magnitude being determined by a mathematical exercise rather than the ECOSSs. This would affect the Utilities' next rate cases.
- There is no way to determine the specific amount of total Account 904 costs allocated to each service classification and each service type (sales or transportation).
- For Peoples Gas, Staff's approach shifts too much gas cost-related Account 904 costs to S.C. No. 1 and not enough to S.C. No. 2. In particular, Staff's approach shifts too much of such costs to Peoples Gas' S.C. No. 1 sales customers and, apparently, none to S.C. No. 1 transportation customers although a small amount of gas cost related Account 904 costs should be allocated to them.
- For North Shore, Staff's approach shifts too little gas cost-related Account 904 costs to S.C. No. 1 and too much to S.C. No. 2.

NS-PGL Ex. VG-3.0 at 12-19.

Additionally, Staff, in its discussion of Account 904 rate design issues, disputes the Utilities' statement that Account 904 costs cannot be accurately identified and quantified under Staff's rate approach and cited Ms. Grace's Surrebuttal testimony as support. Staff IB at 150. Staff apparently misunderstood Ms. Grace's testimony. What Ms. Grace was able to do was to derive amounts from Staff's rate schedules in a logical manner, but these amounts were inconsistent with Staff's revenue requirement schedules. Clearly, there is a problem with Staff's rates schedules. Specifically, Ms. Grace explained:

> Her [Ms. Harden's] formulaic methodology, which treats all expenses equally, is akin to a black box that would not allow the Utilities to accurately quantify nor identify the amount of total Account 904 Costs which are included in their base rates. Using Ms. Harden's gas cost related Account 904 Costs alone would cause the Utilities to incorrectly refund amounts below the artificially derived and much too high, Account 904 Costs arising from her rate design proposals. This is evidenced in Ms. Harden's Account 904 Costs shown in NS-PGL Exs. VG-3.1N and VG-3.1P, which show that Account 904 Costs from her rate proposals exceed that in Staff's proposed revenue requirements, which underlie her rates.

NS-PGL Ex. VG-3.0 at 20. For Peoples Gas, the gas cost-related Account 904 costs that could be derived from Staff witness Harden's proposed rates are $2.2 million over the amount of such costs in Staff's underlying revenue requirement and for North Shore the amount is $628,000. NS-PGL Exs. VG-3.1N and 3.1P. Staff, incorrectly, attributes the difference to the rate design difference between Staff and the Utilities. The difference has nothing to do with the Utilities' proposals, as Ms. Grace's comparison was between one Staff proposal (revenue requirement) and another Staff proposal (rates). *Id*.

The Utilities assert that only they have presented ECOSSs and rate methodologies that are sufficient to develop final rates based on the Commission's final Order in this proceeding.

b) Staff

The Companies and Staff have each proposed their own rates in this proceeding. Staff witness Harden's rates are attached to her rebuttal testimony as schedules, 24.1 N for North Shore and 24.1 P for Peoples Gas. Each one's rates are based upon their own recommendations for what the Companies' revenue requirement should be. Once the Commission determines a revenue requirement, Staff argues that Ms. Harden's Schedule 24.1 can be modified to quickly set final rates for the Companies.

The idea behind Ms. Harden's Schedule 24.1 is that, in general, Ms. Harden agreed with the Companies proposed rate design with the exception of the Companies' handling of Account 904-uncollectible expense cost allocation and their desire for an increase in the amount or percentage of fixed cost recovered through the customer charge. Staff Ex. 24.9 at 12. Given that general agreement with the Companies' rate design with the exception of their handling of Account 904 expenses and the increase in fixed cost recovery through the customer charge, Ms. Harden's Schedule 24.1 N and 24.1 P adjusts the Companies' proposed rates based upon Staff's revenue requirement compared to the Companies' as a ratio after accounting for Ms. Harden's position on Account 904 expenses and maintaining the same fixed cost recovery percentage of 50% for North Shore and 43% for Peoples Gas in the customer charge which was approved in the Companies last rate cases. *Id*. at 13-14. Whatever the revenue requirement is determined to be by the Commission in its final Order it can be input into the schedule, which will then automatically calculate final rates. *Id*. at 18.

One significant area of disagreement between the Companies and Staff regarding where any rate increase should be allocated concerns the customer charge. As mentioned above and discussed in more detail later in this brief, Staff witness Harden recommended that the percentage of fixed costs recovered through the customer charge should remain at 50% for North Shore and 43% for Peoples Gas. The Companies on the other hand are seeking to recover a greater portion of any rate increase through an increase in the percentage of fixed costs recovered through the customer charge. Staff objects to increasing the customer charge to recover more fixed costs for a number of reasons, one objection being that the Companies have in place Rider VBA.

Rider VBA was approved by the Commission in the last rate case "in order to provide a more stable and reliable revenue stream." Rider VBA was designed to address the fact that, according to the Companies, a significant portion of fixed costs were recovered through volumetric charges and that there could be over or under recovery based upon actual volumes. Staff Ex. 10.0 at 9. With Rider VBA, North Shore's and Peoples Gas' fixed cost percentage recovered could be almost 98% for Peoples Gas and would remain at 99% for North Shore based upon the proposals in their testimony. *Id*. Since Rider VBA gives the Companies fixed cost recovery that is so high, it is not necessary to allow the Companies to recover more fixed costs through the customer charge or all Account 904 uncollectible expense solely through the customer charge.

Because the Companies have Rider VBA they are unique from the other gas utilities in Illinois that do not have a Rider VBA. While other utilities in Illinois (Nicor Gas, AmerenCILCO Gas, AmerenCIPS Gas and AmerenIP Gas) sought approval of decoupling riders like the Companies Rider VBA and were denied, those utilities were allowed to recover 80% of their fixed costs through the customer charge. Staff Ex. 24.0 at 6. The Companies cannot cite to any prior Commission decision where a utility was allowed both a decoupling rider like the Companies Rider VBA and high percentage fixed cost recovery through the customer charge like the other gas utilities in Illinois. The Commission should deny the Companies request to become that utility.

c) Commission Analysis and Conclusion

The Commission agrees that the Utilities proposed a reliable means of allocating the revenue increases approved by this Order. Staff's method appears to have inconsistencies and, consequently, cannot be adopted. However, Staff will be able to review the Utilities' compliance rates. No intervenor proposed a rate increase allocation method that addresses all rates and services. Accordingly, the Commission concludes that the Utilities should use their ECOSSs and rate design methodologies to allocate the rate increase and develop compliance rates based on this Order.

2. Account 904 Uncollectible Expense

a) Utilities

Account 904 includes uncollectible expenses. In their ECOSSs, the Utilities each functionalized Account 904 costs to the customer function, Customer Accounts category; classified these costs to the Customer category; and allocated these costs based on the "Bad Debt allocation methodology." NS-PGL Ex. JCHM-2.0 at 8-9. Under the Bad Debt allocation methodology, the Utilities calculated the average historical bad debt net write-offs per customer by customer class as of the twelve months ended June 30, 2008, and applied that average to the customer counts by customer class for the test year. NS Ex. JCHM-1.0 at 17-18; PGL Ex. JCHM-1.0 Rev. at 18.

The Utilities' assert that their functionalization, classification and allocation are proper. For cost classification purposes, Account 904 costs are a function of customers' unpaid bills. The bills' components (fixed or variable; customer or distribution charges) are irrelevant. If a customer does not pay his bill, the unpaid amount becomes an uncollectible account expense, irrespective of the underlying components of the unpaid bill. NS-PGL Ex. JCHM-2.0 at 9. According to the Utilities, Staff's disagreement with the Utilities' treatment of Account 904 costs in their ECOSSs incorrectly mingles cost of service and rate design principles, by relying on the fixed and variable nature of the bill components as a reason for a cost of service study decision. Staff Ex. 24.0 at 24; Tr. at 952. Staff witness Harden agrees that the underlying bill components are a function of rate design and not the ECOSSs. Tr. at 952-953. As Staff also agrees, the ECOSSs, including cost classification, are used to develop the rate design and not *vice versa*. *Id*. at 951, 953. Finally, Staff agrees that the Utilities' ECOSSs witness would not have taken the rate design into account when preparing the ECOSSs. *Id*. at 953. Consequently, when determining the proper classification of Account 904 costs, the underlying rate design (fixed and variable charges) would not have affected and provides no support for the proper classification.

Also, the Utilities assert that Staff's terminology is confusing. While it is true that some rate designs include customer, distribution and demand charges, that is neither a necessity nor is it true for all the Utilities' service classifications. For example, it is apparent from Staff witness Harden's own rate exhibits that S.C. Nos. 1 and 2 for each company include a customer charge and a distribution charge but no demand charge. Staff Ex. 24.0, Scheds. Staff Ex. 24.1 N (Corr.) and 24.1 P (Corr.). What is the case, however, is that classification in the ECOSS looks at commodity, demand (capacity) and customer categories. NS Ex. JCHM-1.0 at 8; PGL Ex. 1.0 Rev. at 8.

For allocation purposes, Staff relied on language from the Order in the Utilities' last rate cases to argue that the Utilities should spread these costs according "to the respective demand, customer and commodity classifications by the relative weight or percentage of revenue requirement from each customer class resulting from various categories of costs." Staff Ex. 10.0 at 3-4. The Utilities disagree with this argument for several reasons.

First, Staff's recommendation is circular in nature. By "circular", the Utilities mean that one cannot calculate an equation without first having one of its components calculated, but one cannot calculate that component without having the answer to the equation. In the context of the Account 904 recommendation, one component of the revenue requirement calculation is operating expenses. Account 904 costs are one piece of operating expenses. Staff's proposal requires determining the revenue requirement by class in order to spread the Account 904 costs to the classes. However, one cannot compute the revenue requirement by customer class without knowing the amount of Account 904 costs allocated to the customer classes. NS-PGL Ex. JCHM-2.0 at 3-5.

Second, the circular nature of the recommendation means that the Utilities would not be able to implement it through their ECOSSs, *i.e.*, the ECOSSs will not perform the allocation as it would under the Utilities' method. To comply with the 2007 rate case Order, the Utilities "forced" (hard coded) a result into their ECOSSs. NS-PGL Ex. JCHM-2.0 at 6. While the Utilities were able to comply with the Order, it was only possible by going outside of the ECOSSs. Tr. at 184-185.

Third, the Staff witness tried to sidestep the circularity problem by assuming, without support, that the 2007 rate case Order is using the term "revenue requirement" in this context to mean revenue requirement minus the uncollectible expense. Staff Ex. 24.0 at 23. The Staff witness agrees, however, that the Order does not include that gloss on the "revenue requirement" definition. Tr. at 958-959. Moreover, Staff has not explained why such an irregularity -- a unique definition of "revenue requirement" for the sole purpose of the Account 904 costs -- would be proper in building an ECOSS.

Fourth, other than Peoples Gas and North Shore, there is no evidence that any other Illinois utility uses this approach. The Utilities used this approach in their compliance filings solely due to the requirement in the 2007 rate case Order. Staff agrees that no other Illinois gas utility uses Staff's recommended approach. NS-PGL Ex. JCHM-2.0 at 7; NS-PGL Ex. JCHM-2.2; Tr. at 43. Staff witness Harden did not use this approach in either of two cost of service studies that she prepared as a Commission witness, nor did she recommend it in the approximately 15 other rate proceedings in which she was the Commission's main rates witness. Tr. at 959-960.

The Utilities proposed different customer charges for transportation and sales customers. Differentiation is proper as a matter of cost causation, *i.e.*, costs should be allocated to those who cause the utility to incur the costs. NS Ex. JCHM-1.0 at 7; PGL Ex. JCHM-1.0 Rev. at 7. When a sales customer does not pay his bill, part of that bill includes gas purchased from the utility. When a transportation customer does not pay his bill, that is not the case. Tr. at 973:2-21. Consequently, the gas cost-related Account 904 expense associated with sales and transportation customers differs and should be recognized in rates. Currently, this differential is reflected in the distribution charges. There are two major reasons why differentiation in the customer charge is the better rate design. NS Ex. VG-1.0 Rev. at 11-12; PGL Ex. VG-1.0 Rev. at 12-13.

First, the ECOSSs properly classified Account 904 costs as "customer" costs. Consequently, the rate design developed from the ECOSSs should address Account 904 responsibility in the customer charge. NS-PGL Ex. VG-2.0 Rev. at 5. Ideally, the customer charge would include all costs classified as customer costs. However, for S.C. No. 1, in the interest of gradualism, the Utilities set their customer charges below the embedded customer costs. NS Ex. VG-1.0 Rev. at 13; PGL Ex. VG-1.0 Rev. at 14. For S.C. No. 2, meter classes 1 and 2, all customer costs are recovered through the customer charge, but in the interest of gradualism, less than all customer costs would be recovered through the meter class 3 customer charge. NS Ex. VG-1.0 Rev. at 18; PGL Ex. VG-1.0 Rev. at 19-20.

Second, customer charge differentiation better addresses customer migration from sales to transportation service and *vice versa*. When a customer moves from one service to the other, the customer charge differentiation means that the gas cost-related Account 904 expense moves with the customer. NS Ex. VG-1.0 Rev. at 12; PGL Ex. VG-1.0 Rev. at 13. Customer migration also raises two practical considerations that differentiation in the customer charge can easily address. Adjustments under the Utilities' decoupling mechanism, Rider VBA, are based on rate case margins, which means that distribution revenues drive the calculation. Setting rates with differentiation in the distribution charges means that, when customers move between sales and transportation service, the resulting distribution revenues (actual margins) are skewed from the rate case margins more than would be the case were the differentiation in the customer charge. Consequently, Rider VBA adjustments are greater than would otherwise be the case. Moreover, differentiation in the distribution charges means that there are different Rider VBA rate case margin baselines for sales and transportation customers and, consequently, different Rider VBA adjustments for sales and transportation customers. While this has no impact whatsoever on the accuracy of the Rider VBA adjustments, it does unnecessarily require four, instead of two, adjustments (S.C. No. 1 sales and transportation and S.C. No. 2 sales and transportation). NS-PGL Ex. VG-2.0 Rev. at 6-7.

Were the Commission to accept Staff's proposal for treatment of Account 904 costs in the ECOSSs, it would still be proper to differentiate for the gas cost-related Account 904 expense in the customer charge. Even under Staff's theory, the largely fixed revenue requirement would be the basis for the Account 904 cost allocation, so most costs would be allocated as fixed costs. Consequently, allocation to the fixed customer charge is reasonable under the Utilities' and the Staff's approach. NS-PGL Ex. VG-3.0 at 7.

In sum, differentiation in the customer charges for sales and transportation customers to adjust for gas cost-related Account 904 expense is the result that properly flows from classifying the Account 904 costs as "customer" costs. This rate design best reflects cost causation principles, and, for that reason alone, it should be approved. Moreover, an ancillary benefit is halving the number of Rider VBA adjustments and eliminating the sales and transportation distinction in those adjustments.

b) Staff

Staff witness Harden recommended that Account 904-uncollectible expense be apportioned to customer, distribution, and demand cost classifications so that the expenses are recovered from the blend of charges that comprise the uncollectible expense. Her position is consistent with the Commission's Order in the Companies' last rate case. Staff Ex. 10.0 at 5-6. In North Shore's and Peoples Gas' last rate case, the Commission directed the Companies to do two things with respect to Account 904-uncollectible expense. First, the Companies were directed to segregate out uncollectible expense associated with sales customers' gas purchases from transportation customers' uncollectible expenses so that there were differentiated distribution rates for sales and transportation customers. The goal being that transportation customers who buy gas from suppliers other than North Shore and Peoples Gas would not pay rates that included uncollectible expenses for gas purchases for sales customers who purchase their gas through the purchased gas adjustment clause ("PGA"). In the current docket, Utilities witness Grace agreed to continue this "differentiation" between sales and transportation customers, but believes the differentiation should be reflected in the customer charge.

The second direction given to the Companies by the Commission was that because uncollectible expenses were found to be "… classified as a combination of customer costs, demand costs, and commodity costs including gas costs" uncollectible expense should be apportioned by relative weight to not only the customer cost classification but also demand and commodity classifications. Docket 07-0241/07-0242 (Consol.), Order at 201. That direction was based upon the Staff's analysis in the docket which the Commission found to be "clear, thorough and highly persuasive." *Id*.

In their filings for these rate cases, the Companies followed some of the direction given to them by the Commission concerning Account 904 uncollectible expense but did not follow all of the Commission's direction. The Companies did provide for differentiated rates for sales and transportation customers in their filings, but they ignored the Commission's direction on apportioning uncollectible expense to not only the customer classification but also to apportion some of the uncollectible expense to demand and commodity classifications. Tr. at 45-48, August 24, 2009.

Consistent with Staff's position in the last rate case, it was illogical to Staff witness Harden to allow the recovery of the uncollectible costs solely through the customer charge, which is a fixed charge, when one of the charges which comprises two-thirds of a customer's bill (gas costs) will vary by usage. *Id*. at 6. Even the Companies' witness Hoffman-Malueg agreed "that a high cost of gas could be one attributable factor as to why a customer does not pay their bill." NS-PGL Ex. JCHM-3.0, at 4-5. Since gas costs will vary by usage, the only reasonable position to Staff is that some recovery of the uncollectible expense must occur based upon usage rather than seeking one hundred percent recovery through the non-usage based fixed customer charge. Staff Ex. 10.0 at 6.

The Companies, through the testimony of witnesses Hoffman Malueg and Grace, raise several arguments against Staff's position concerning Account 904 uncollectible expense. One of the Companies' arguments in Rebuttal against the Commission's decision in the last rate case was that if Account 904 uncollectible expense was to be classified by relative weight of the revenue requirement and the revenue requirement is derived from components including expense accounts (e.g., Account 904) there is a circularity problem with the Commission's/Staff's position. NS-PGL Ex. JCHM-2.0 at 3. As Ms. Harden explained, the uncollectible expense in each customer class is apportioned based on the relative percentage or weight of costs other than uncollectible expense to the demand, customer and commodity classifications. NS-PGL Ex. JCHM-2.3.

Another argument raised by the Companies against Staff's position is that the Commission's Order in 2007 "… did not appear to set a generally applicable policy considering that other gas utilities have not been directed to use the approach stated in the 2007 Final Order." NS-PGL Ex. JCHM-3.0, at 2. Companies witness Hoffman Malueg fails to recognize the obvious - that the Order in 07-0241/0242 (consol.) which addressed Account 904 uncollectible expense was specifically directed to the Companies while the Orders for the other gas utilities were for utilities who had their own different set of facts and circumstances and were specifically addressed to those other gas utilities. As Staff witness Harden testified, the Companies have not provided any new information about Account 904 in this Docket which warrants a revision to the Commission's ruling on the issue from its prior Order, the Companies have only provided a new argument about customer migration discussed below. Staff Ex. 10.0 at 4.

The Companies also argue that even though gas usage is a cause for uncollectible costs in Account 904, given the other varying causes for why a customer does not pay their bill, the decision to classify Account 904 solely to the customer classification, is appropriate for the various reasons stated in Companies witness Hoffman Malueg's rebuttal testimony. NS-PGL Ex. JCHM-3.0 at 2-3. The fact that the Companies do not dispute that gas usage is a cause for uncollectible expense yet the Companies continue to assign all of the costs to the customer charge component of the bill highlights the narrow focus of their position. The Companies want to recover all of the costs through the fixed customer charge no matter what the evidence shows. Staff's position on the other hand, is broader and more encompassing of the evidence in the record and not results driven like the Companies' proposal.

Companies witness Grace makes a Rider VBA/customer migration argument against Staff's proposal concerning Account 904 uncollectible expense. Ms. Grace, like Companies witness Hoffman Malueg believes that Account 904 costs are customer related. NS-PGL Ex. VG-3.0 at 4. For that reason, she believes that the differentiation of gas cost related Account 904 Costs should be reflected in different customer charges instead of different distribution charges for sales and transportation customers (Currently the Companies have different distribution charges for sales and transportation customers). *Id*. Ms. Hoffman Malueg then makes the point that due to the fact that sales and transportation customers have different distribution charges, there have been different Rider VBA charges and credits for sales and transportation customers. *Id*. Ms. Grace's VBA argument seems to be that if Account 904 costs are put into the customer charge for both sales and transportation customers, those customers would be better able to compare the delivery charge costs of the Companies' sales service versus its transportation service since the number of Rider VBA baselines would be reduced from four to two. *Id*. at 6. Ms. Grace also argues that by having different distribution rates rather than different customer charges, the migration of customers from sales to transportation has skewed the differentiation of revenues between sale and transportation service. *Id*. at 4. It is Staff's position that there is little benefit from going from four to two VBA calculation adjustments (Staff Ex. 24.0 at 5) and if migration is a problem for Rider VBA then it should be addressed at the conclusion of the Rider VBA pilot when Rider VBA will be evaluated rather than modifying the pilot in midstream. *Id*. at 4.

Finally, Staff notes the Utilities witness Grace argues that due to recent enactment of Senate Bill 1918 (Public Act 096-0333) Account 904 costs that are recovered through base rates must be identifiable and accurately quantified. NS-PGL Ex. VG-3.0, at 20. Ms. Grace seems to imply that Staff witness Harden's costs are not identifiable and accurately quantified yet the example she provides in her Surrebuttal testimony establishes the opposite. Clearly they are identifiable given that Ms. Grace is able to quantify them for purposes of arguing that an improper amount of Account 904 costs would be refunded under Ms. Harden's rate design proposal. See, NS-PGL Ex. VG-3.0, at 22. As to whether the amount is accurately quantified, any difference between Ms. Harden's amount and Ms. Grace's amount is due to the fundamental difference of opinion between Staff and the Companies as to whether Account 904 costs are solely customer costs.

c) Commission Analysis and Conclusion

Apportioning uncollectible costs through the use of different charges for transportation and sales customers, as adopted by the Commission in the last rate proceeding and implemented by the Utilities here, is appropriate. This decision is not changed. In its Brief on Exceptions, the AG urges the Commission to direct the Utilities to implement the same customer charge for transportation and sales customers. The AG cites the testimony of Mr. Rubin that says it is a social obligation of all customers to pay for non-paying customers. Because the AG did not raise this issue in either its Initial or Reply Brief, but rather waited until Exceptions, the Commission cannot adopt this proposal at this time.

After reviewing the testimony and Briefs, the Commission cannot say that either approach to Account 904 costs is incorrect. Nevertheless, we find the approach proposed by the Utilities to be simpler and in that respect, superior. First we note that the calculation of Rider VBA amounts is simplified with the Utilities' approach in that it would require two calculations instead of four. Also, we find that the Utilities' classification of Account 904 costs as "customer" costs in their ECOSSs is proper and it reasonably follows from that classification that differentiation in the customer charges is the better approach. This approach will enable the Utilities to use their ECOSSs to implement the approved rate design.

More important for our conclusion, however, is the interplay between how Account 904 costs are treated and the requirements under Senate Bill 1918. Although not raised by the Utilities in their briefs, Utilities witness Grace points out that:

> the recent enactment of Senate Bill 1918 (Public Act 096-0033) allows utilities to recover, through an automatic adjustment clause tariff, the incremental difference between its actual uncollectible amount as set forth in Account 904 and in the utility's most recent Form 21 IICC and the uncollectible amount included in the utility's base rates. Due to this new law, the Utilities are withdrawing their Respective Rider UEA tariffs and will propose a tariff pursuant to the legislation to recover its incremental Account 904 Costs. As a result, the Account 904 Costs that are recovered through base rates need to be accurately quantified and specifically identifiable for each affected rate class.

NS-PGL Ex. VG-3.0 at 20. Ms. Grace goes on to note the many difficulties of using the rate design proposed by Staff, but the Commission also notes that by recovering all the Account 904 costs through a fixed customer charge, the calculation of costs recoverable (or refundable) under the uncollectible rider would be simplified. Because of the enactment of Senate Bill 1918 since the time of the Utilities' last rate case, the Commission adopts the Utilities' treatment of Account 904 for both the ECOSS and rate design.

3. Uniform Numbering of Service Classifications

a) Utilities

Staff proposed that the Utilities adopt uniform numbering for their service classifications. For example, S.C. No. 1 for each company is Small Residential Service, but the Large Volume Demand Service is S.C. No. 3 for North Shore and S.C. No. 4 for Peoples Gas. Staff Ex. 10.0 at 10-12. The Utilities agreed to assess their customer information systems to determine if they can implement uniform numbering in their next rate cases. NS-PGL Ex. VG-3.0 at 9.

b) Staff

As demonstrated in Staff witness Harden's table 1 in her Direct Testimony, North Shore Gas and Peoples Gas for the most part have the same customer classes, but each Company has different service classification numbers to identify customer classes. Staff Ex. 10.0 at 10. Staff witness Harden recommended that in order to limit confusion for customers with accounts in both service territories and to simplify the rate-making process it be beneficial for the Companies to adopt a uniform set of service classification numbers. *Id*. In Rebuttal, Staff witness Harden testified that the Companies should be ordered to assess their customer information system and adopt a uniform numbering system for their service classifications in their next rate case.

In Surrebuttal testimony, Utilities witness Grace indicated that the Companies would "assess their customer information systems to determine if they can implement uniform numbering of their service classifications. If those assessments yield no identifiable problems, the Utilities will propose uniform service classifications in their next rate cases." NS-PGL Ex. VG-3.0 at 9.

The Companies proposal set forth above in Surrebuttal is acceptable to Staff. Therefore Staff considers this issue to no longer be contested. The Commission's final order in this matter should reflect the resolution of the issue as set forth by Utilities witness Grace in her Surrebuttal testimony.

c) Commission Analysis and Conclusion

We adopt the proposal set out by Utilities witness Grace. In Surrebuttal testimony, she states that the Utilities will assess their customer information systems to determine if they can implement uniform numbering of their service classifications. Further, she states that if this assessment yields no identifiable problems, the Utilities will propose uniform service classifications in their next rate cases. Staff accepted this proposal. Accordingly, this issue is uncontested.

B. Service Classification Rate Design

1. Uncontested Issues

a) North Shore Service Classification Nos. 2 and 3 Eligibility Criterion

(1) The Record

North Shore proposed an eligibility criterion for each of S.C. Nos. 2 (General Service) and 3 (Large Volume Demand Service). S.C. No. 2 would be available to customers who consume an average of 41,000 monthly therms or less, and S.C. No. 3 would be available to customers using more than 41,000 monthly therms. NS Ex. VG-1.0 Rev. at 10. Adding such requirements ensures that customers are served under the rate classes for which North Shore derived costs and charges. NS-PGL Ex. VG-2.0 Rev. at 42-44. Staff witness Sackett reviewed the proposal. He concluded that North Shore's arguments were reasonable and recommended that the Commission approve the proposal. Staff Ex. 26.0 at 4.

(2) Commission Analysis and Conclusion

The Commission finds that it makes sense for service classifications to specify eligibility. It is consistent with cost causation principles. Eligibility criteria help ensure that customers take service under the rates specifically designed for customers with the same usage characteristics and for which the utility derived costs and charges. North Shore supported its proposed usage criterion, and Staff concluded it was reasonable. The Commission finds that it is reasonable and approves the proposed eligibility criterion for North Shore's S.C. Nos. 2 and 3.

b) North Shore Service Classification No. 3

(1) The Record

S.C. No. 3 is North Shore's Large Volume Demand Service. According to Ms. Grace, North Shore proposed setting this service classification at cost to help meet its objective of maintaining customers on the system. North Shore proposed: changing the demand charge from a declining block to a flat rate to mitigate the impact on customers who migrate to S.C. No. 3 from S.C. No. 2 and setting it at 67% of cost; increasing the customer charge to set it at cost; revising the standby service charge and removing Account 304 ("Land and Land Rights") costs; increasing the distribution charge; and eliminating the written contract requirement. NS Ex. VG-1.0 Rev. at 10, 21-22. Staff witness Harden recommended approval of the various aspects of North Shore's proposed rate design. Staff Ex. 10.0 at 25-29. Staff witness Sackett agreed that removing Account 304 costs from the standby service charge was appropriate. Staff Ex. 26.0 at 45.

(2) Commission Analysis and Conclusion

The Commission finds that North Shore's proposals are reasonable, including removing Account 304 costs from the standby service charge calculation. Only Staff addressed this service classification, and Staff had no proposed changes. The Commission agrees that it is just and reasonable to set this large volume demand service classification at cost, and it approves North Shore's proposed S.C. No. 3 rate design and its elimination of the contract requirement.

c) North Shore Service Classification No. 5

(1) The Record

North Shore proposed to eliminate S.C. No. 5, Standby Service, and transfer customers to S.C. No. 2. Ms. Grace explained that, other than using gas for standby service, the customers served under S.C. No. 5 have no similar usage or cost characteristics. NS Ex. VG-1.0 Rev. at 23. Staff witness Harden agreed that the proposal was appropriate. Staff Ex. 10.0 at 32.

(2) Commission Analysis and Conclusion

The Commission finds that it is reasonable to eliminate this service classification. As we concluded in connection with the eligibility criterion for S.C. Nos. 2 and 3, it is appropriate for customers with similar usage characteristics to be served under the same rate. Only Staff addressed this proposal, and Staff agreed that elimination of S.C. No. 5 was appropriate. The Commission approves North Shore's proposal to eliminate S.C. No. 5.

d) North Shore Service Classification No. 6

(1) The Record

North Shore proposed no changes to S.C. No. 6, Contract Service for Electric Generation. NS Ex. VG-1.0 Rev. at 23. It is a negotiated rate service. Staff witness Harden noted that there are currently no S.C. No. 6 customers and proposed no changes. Staff Ex. 10.0 at 32-33.

(2) Commission Analysis and Conclusion

There are no proposed changes to this service classification, and the Commission finds that none are required.

e) Peoples Gas Use of Equal Percentage of Embedded Cost Method ("EPECM")

(1) The Record

Peoples Gas proposed to use the equal percentage of embedded cost method ("EPECM") to allocate the additional revenue requirement between S.C. Nos. 1 and 2. Peoples Gas stated that it used, and the Commission approved, the EPECM in its last three rate cases (Dockets 91-0586, 95-0032 and 07-0242). The ECOSSs showed that rates for S.C. Nos. 1, 2, 4 and 8 were below cost. Peoples Gas proposed to move S.C. Nos. 4 and 8 to cost and to use the EPECM to move S.C. Nos. 1 and 2 gradually toward cost. Ms. Grace explained that, using the EPECM, Peoples Gas allocates the increase in proportion to the embedded cost of service for these two service classifications. S. C. No. 1 would be set below cost and S.C. No. 2 would be set above cost, but each less so than under rates set in the 2007 rate case. PGL Ex. VG-1.0 Rev. at 8-9. Staff agreed that using the EPECM was appropriate and helps to mitigate the bill impact on small residential customers. Staff Ex. 10.0 at 36.

(2) Commission Analysis and Conclusion

The Commission finds that, in the interest of gradualism, it is appropriate that Peoples Gas' S.C. Nos. 1 and 2 not be moved fully to cost in this proceeding. As we have found in prior proceedings, the EPECM is a reasonable way to gradually move toward cost. Only Staff addressed the EPECM, and Staff supported its use. The Commission approves Peoples Gas' proposed use of EPECM to allocate the additional revenue requirement between S.C. Nos. 1 and 2. The Commission further concludes that, in future rate cases, Peoples Gas should continue to steadily move these service classifications to the embedded cost of service.

f) Peoples Gas Service Classification Nos. 2 and 4 Eligibility Criterion

(1) The Record

Peoples Gas proposed a maximum eligibility criterion for S.C. No. 2 (General Service) that mirrors its current minimum eligibility criterion for S.C. No. 4 (Large Volume Demand Service). S.C. No. 2 would be available to customers who consume an average of 41,000 monthly therms or less. Ms. Grace stated that S.C. No. 4 would remain available to customers who consume an average of more than 41,000 monthly therms. PGL Ex. VG-1.0 Rev. at 11. She explained that adding an eligibility requirement for S.C. No. 2 that mirrors the existing S.C. No. 4 requirement ensures that customers are served under the rate classes for which Peoples Gas derived costs and charges. NS-PGL Ex. VG-2.0 Rev. at 42-44. Staff witness Sackett reviewed the proposal. He agreed that Peoples Gas' arguments were reasonable and recommended that the Commission approve the proposal. Staff Ex. 26.0 at 4.

(2) Commission Analysis and Conclusion

As with comparable provisions for North Shore, the Commission agrees that eligibility criteria are reasonable and appropriate for service classifications. In this instance, the Commission notes that Peoples Gas already has such a criterion for its

S.C. No. 4 and is proposing no change to that criterion but would mirror it in S.C. No. 2. The Commission finds that it is reasonable and approves the proposed eligibility criterion for Peoples Gas' S.C. No. 2 and no change to its existing S.C. No. 4 criterion.

g) Peoples Gas Service Classification No. 4

(1) The Record

S.C. No. 4 is Peoples Gas' Large Volume Demand Service. Ms. Grace stated that Peoples Gas proposed setting this service classification at cost to help meet its objective of maintaining customers on the system. Peoples Gas proposed: changing the demand charge from a declining block to a flat rate to mitigate the impact on customers who migrate to S.C. No. 4 from S.C. No. 2 and setting it at 55% of cost; increasing the customer charge to set it at cost; revising the standby service charge and removing Account 304 costs; increasing the distribution charge; and eliminating the written contract requirement. PGL Ex. VG-1.0 Rev. at 11-12, 22-24. Staff witness Harden recommended approval of the various aspects of Peoples Gas' proposed rate design. Staff Ex. 10.0 at 48-53. Staff witness Sackett agreed that removing Account 304 costs from the standby service charge was appropriate. Staff Ex. 26.0 at 45.

(2) Commission Analysis and Conclusion

The Commission finds that Peoples Gas' proposals are reasonable, including removing Account 304 costs from the standby service charge calculation. Only Staff addressed this service classification, and Staff had no proposed changes. The Commission agrees that it is reasonable to set this large volume demand service classification at cost, and it approves Peoples Gas' proposed S.C. No. 4 rate design.

h) Peoples Gas Service Classification No. 5

(1) The Record

Peoples Gas proposed no changes to S.C. No. 5, Contract Service for Electric Generation. PGL Ex. VG-1.0 Rev. at 25. It is a negotiated rate service. Staff witness Harden noted that there are currently no S.C. No. 5 customers and proposed no changes. Staff Ex. 10.0 at 53-54.

(2) Commission Analysis and Conclusion

There are no proposed changes to this service classification, and the Commission finds that none are required.

i) Peoples Gas Service Classification No. 6

(1) The Record

Peoples Gas proposed to eliminate its S.C. No. 6, Standby Service, and transfer customers to S.C. No. 2. Peoples Gas explained that, other than using gas for standby service, the customers served under S.C. No. 6 have no similar usage or cost characteristics. Consequently, it is more appropriate to serve these customers under a general service rate. PGL Ex. VG-1.0 Rev. at 24. Staff witness Harden concluded that the proposal was appropriate. Staff Ex. 10.0 at 54-57.

(2) Commission Analysis and Conclusion

The Commission finds that it is reasonable to eliminate this service classification. As we concluded in connection with the eligibility criterion for S.C. Nos. 2 and 4, it is appropriate for customers with similar usage characteristics to be served under the same rate. Only Staff addressed this proposal, and Staff agreed that elimination of S.C. No. 6 was appropriate. The Commission approves Peoples Gas' proposal to eliminate S.C. No. 6.

j) Peoples Gas Service Classification No. 8

(1) The Record

Peoples Gas proposed to set S.C. No. 8, Compressed Natural Gas Service, at cost. The customer charge would decrease and the distribution charge would increase. PGL Ex. VG-1.0 Rev. at 25. Staff witness Harden concluded that the proposal was appropriate. Staff Ex. 10.0 at 57-58.

(2) Commission Analysis and Conclusion

The Commission agrees that it is reasonable to set this service classification at cost. The Commission notes that only Staff addressed this service classification, and it recommended no changes to Peoples Gas' proposal. The Commission finds that Peoples Gas' proposal is just and reasonable and approves it.

2. Contested Issues

a) North Shore and Peoples Gas Service Classification Nos. 1 and 2 – Customer Charge

(1) Utilities

North Shore's S.C. No. 1 would be set at cost. North Shore proposed to increase its customer charge, and it would recover only 55% of fixed costs. The distribution charges would continue to be in the form of a declining two block rate with the first block (0 to 50 therms) recovering two-thirds of demand, commodity and remaining customer costs and the second block (over 50 therms) recovering the remaining costs. NS Ex. VG-1.0 Rev. at 12-14.

Peoples Gas proposed to increase its customer charges. Peoples Gas' S.C. No. 1 rates would be set below cost. The customer charge would recover less than the embedded customer costs and would be set to recover 54% of fixed costs. The distribution charges would continue to be in the form of a declining two block rate with the first block (0 to 50 therms) recovering 65% of demand, commodity and remaining customer costs and the second block (over 50 therms) recovering the remaining costs. PGL Ex. VG-1.0 Rev. at 13-15.

Peoples Gas proposed to add an additional meter class (meter class 3) to S.C. No. 2. It then proposed to increase the customer charges and move the charges for all three meter classes closer to cost. For the same reasons discussed in connection with S.C. No. 1, sales and transportation customers would have different customer charges to reflect differentiation for gas cost related Account 904 expenses. For meter classes 1 and 2, Peoples Gas would recover all customer costs and a portion (20%) of demand costs in the customer charge. For meter class 3, it would recover no demand costs in the customer charge, in the interest of gradualism. This directly affects the distribution charges in the declining three block structure. The remaining costs would be allocated to the distribution blocks. The charges for all three blocks would increase, but the increase for the third block would be larger, which results from the fact that no demand costs would be recovered through the meter class 3 customer charge. Only 35% of the S.C. No. 2 revenue requirement would be recovered under fixed charges. PGL Ex. VG-1.0 Rev. at 18-20. Although Staff's rate proposals in its Rebuttal testimony results in an overall increase in fixed cost recovery as well as for S.C. No. 2, Staff contends that there should be no increase in the amount of fixed costs recovered through the customer charge because this would be a "mid stream alteration to the design of the [Rider VBA] program." Staff Ex. 24.0 at 7. NS-PGL Ex. VG-3.0 at 7, 14.

The Utilities' proposal to increase the customer charge is consistent with prior cases in which the Commission encouraged or approved rate designs that reflect greater recovery of fixed costs in the customer charge. NS Ex. VG-1.0 Rev. at 14-15. In Peoples Gas' 1995 rate case, the Commission, in approving the proposed customer charge, stated that it "in fact, should be increased in future rate proceedings to move it closer to cost." *In re The Peoples Gas Light and Coke Company*, Docket 95-0032 (Order, Nov. 8, 1995). In North Shore's last rate case, the Commission approved an increase in fixed cost recovery through the customer charge to 50% of the S. C. No. 1 revenue requirement. *Peoples 2007* at 269. For Nicor, the Commission approved recovery of 80% of fixed costs through the customer charge. The Commission stated that "[m]oving a greater percentage of fixed cost recovery to fixed charges rather than volumetric charges provides a more stable revenue stream and sends a better price signal to the consumer." *Nicor 2008* at 91.

Staff contends that there should be no increase in the amount of fixed costs recovered through the customer charge because this would be a "mid-stream alteration to the design of the [Rider VBA] program." Staff Ex. 24.0 at 7. The Utilities disagree and note that nothing in the Commission's Order approving Rider VBA (Peoples 2007) states or suggests that rate design could not change while Rider VBA is in effect. Indeed, Rider VBA will not change, although, as Staff agrees, the rate case margins, a factor in the Rider VBA adjustment calculation, must change.

The Utilities further note the proposed customer charges for the service classifications to which Rider VBA applies (S.C. Nos. 1 and 2) remain far below embedded fixed costs. For Peoples Gas, only about 48% of fixed costs would be recovered through fixed charges, which leaves nearly $300 million subject to Rider VBA. For North Shore, only about 56% of fixed costs would be recovered through fixed charges, which leaves nearly $40 million subject to Rider VBA. These are large dollar amounts that the Utilities recover through variable charges and that will factor into the Rider VBA adjustments. According to the Utilities, significant activity will remain under Rider VBA for purposes of reviewing its effect. NS-PGL Ex. VG-2.0 Rev at 9.

The Commission approved Rider VBA only as a pilot program, and it will terminate in March 2012, unless the Utilities request and the Commission approves an extension. *Peoples 2007* at 152. For the affected service classifications, Peoples Gas states that it has only about $15 million in variable costs and North Shore only about $695,000, although significantly larger amounts of fixed costs are recovered through variable charges. If Rider VBA ends, the Utilities would still have a very large amount of fixed costs to be recovered through variable charges. (Even the Utilities' proposal puts only a small dent in this mismatch.) Under Staff's theory, the Utilities could take no steps to mitigate this circumstance during the four years that Rider VBA is in effect, despite the Commission's policy encouraging fixed cost recovery through fixed charges. NS-PGL Ex. VG-2.0 Rev. at 9.

The Utilities note that Staff made the assertion that a utility should not have both a decoupling mechanism and a "high percentage fixed cost recovery through the customer charge like the other gas utilities in Illinois." Staff IB at 144. Nicor and the Ameren gas utilities have 80% fixed cost recovery through their customer charges. Nicor 2008 at 90-91; In re Central Illinois Light Co., Central Illinois Public Serv. Co. and Illinois Power Co., Dockets 07-0588, 07-0589 and 07-0590 (Consol.), at 237 (Order, Sept. 24, 2008). North Shore proposed to increase the recovery from 50% to 55%. The Utilities argue that this is hardly a "high percentage" and certainly not "like the other gas utilities."

(2) Staff

There is no agreement between Staff and the Utilities regarding the customer charge and some agreement regarding the distribution charge. The Utilities seeks a higher percentage of recovery of fixed costs through the customer charge than Staff and they want sales and transportation customers to have different customer charges. Staff witness Harden recommended that for the Utilities' service classification No. 1 the customer charge for both sales and transportation customer should remain the same for both customers and that the customer charge for both sales and transportation customers should be set at 50% of the class revenue requirement determined in the docket. Ms. Harden's position is consistent with the Commission's order in the Utilities' last rate case. The Utilities on the other hand want to recover more fixed costs (56% for North Shore and 54% for Peoples Gas) through the customer charge.

Staff cannot support the Utilities recovering a higher percentage of fixed costs through customer charge given that the Utilities have Rider VBA in place as a pilot program which is intended to address the recovery of fixed costs by allowing the Utilities to recover a higher percentage of fixed costs through the customer charge and would change the dynamics of the pilot program. Staff's position is that the pilot program should be maintained as designed so that its success or failings can be measured throughout the life of the pilot.

In the event the Commission allows the Company to increase the percentage of fixed costs recovered through the customer charge which it should not, Ms. Harden recommended that the customer charge for both sales and transportation customers be set the same. The percentage recovery in that case would be 55% for North Shore and 54% for Peoples Gas of the class fixed costs.

On the subject of the distribution charge there is some agreement between Staff and the Company on certain points. The Company wants to maintain its two step declining block rate structure. Staff witness Harden supports maintaining the current two-step declining block rate structure, which is consistent with the Commission's Order in the last rate case.

(3) Commission Analysis and Conclusion

As discussed under the Account 904 issue, it is appropriate to have different customer charges for sales and transportation customers. The findings in this section do not change that determination.

Before addressing the specific proposals raised, it is important to recognize that Rider VBA will remain in place until March 2012. At that time, Rider VBA will terminate unless the Utilities request an extension and the Commission approves the request.

The Utilities propose to increase the proportion of fixed costs that will be recovered through the customer charge. The Utilities are correct that the Commission has been increasing the proportion of fixed costs recovered through the customer charge in other proceedings. *See Nicor 2008*; *In re Central Illinois Light Co., Central Illinois Public Serv. Co. and Illinois Power Co.*, Dockets 07-0588/07-0589/07-0590 (Consol.) (Order, Sept. 24, 2008). The Commission notes that the Utilities' proposal does not approach the level of fixed costs approved in those dockets. Staff argues, however, that it is inappropriate to change the manner in which the Utilities' fixed costs are recovered while the Rider VBA pilot is in place. We do not agree. The Utilities inform us that sufficient activity will remain under Rider VBA for purposes of reviewing its effect during the pilot period. Moreover, in the event that Rider VBA is not renewed, the slight increase proposed by the Utilities' here will be a benefit in the long run.

b) Tiered Rates

(1) Utilities

AG-CUB-City witness Rubin proposed what he called "tiered rates." His proposal would set seven tiers of flat monthly charges based on a customer's annual usage, determined over an historical two-year period. AG-CUB-City Ex. 2.0 at 28, 38. The Utilities assert that there are sound reasons why tiered rates have not been used for energy companies and that the proposal in these proceedings is conceptually and practically flawed.

According to the Utilities, conceptual flaws with the proposal include that:

- It does not normalize the historical data on which placement in tiers would be based, which can cause the utility to under- or over-earn its revenue requirement. For example, the data that Mr. Rubin used for setting his proposed rates were for a period that was colder than normal. Consequently, relative to normal, he used overstated usage and volumetric revenues.

- It does not take changing customer usage into account. The record shows that, for several reasons, customer usage has been declining. Mr. Rubin used data from mid-2007 through mid-2008 that do not take that fact into account.

- It bases proposed rates on an incomplete data set and a simplistic mathematical extrapolation for many customers. The historical data Mr. Rubin used for Peoples Gas included only 69% of total customers, which means that he assigned almost 239,000 customers to tiers with no usage data for those customers. For North Shore, the comparable figure is 46,000 customers.

- The number and range of the tiers is not fully explained. There are seven total tiers. Some tiers span 500 therms. Two tiers each span 1,500 therms. The last tier is for customers with usage over 5,000 therms. There are no apparent rate design principles underlying the tiers.

The Utilities argue that practical problems with the proposal include that:

- It includes only one set of rates but it would need distinct rates for sales and transportation customers to address gas cost-related Account 904 expenses. Cost causation principles support rate differentiation. Mr. Rubin did not develop distinct rates, nor address the mechanics of developing and implementing distinct rates.

- It would require substantial modifications to the Utilities' customer information systems to track usage and apply the tiers to the Utilities' over 900,000 S.C. No. 1 customers. The proposed rates do not include the costs associated with these modifications, nor do they take into account any transition period needed to develop, test and implement the modifications.

- There are many challenges to placing in tiers customers with less than one year's usage, such as new customers (which may mean the same person with a new account number), customers with gas theft, or customers with other deficiencies with their historical usage.

- Customer disputes about tier placement would raise novel issues for which there are no ready answers.

- Sales revenue forecasting would be complicated.

The AG claims that this is not a "radical proposal" and analogizes to cable television rates. The witness had also analogized to telecommunications services. AG-CUB-City Ex. 2.0 at 29. The analogies are inapt. Even Mr. Rubin acknowledged that tiered rates have not been used for energy services. *Id*. For the industries he identified, customers are able or required to choose, usually in advance, the level of services that they desire, such as minutes, unlimited service, number of channels, premium channels, etc. NS-PGL Ex. VG-2.0 Rev. at 21. Generally, if customers use more than their elected service, they are billed additional charges on each unit of additional service rather than automatically moved by the service provider to a higher priced plan. *Id*. There is no reconciliation, for any reason, under Mr. Rubin's proposal. Tr. at 976-978. The Utilities' customers do not elect the level of gas distribution service that they desire in advance. They consume what they need or desire. Also, there is no evidence that a customer who uses 5,000 annual therms values gas service any more than the customer who uses 1,000 annual therms. NS PGL Ex. VG-2.0 Rev. at 2.

Also, the AG claims that tiered rates would eliminate the need for a decoupling mechanism. That is incorrect. In fact, tiered rates would result in a greater need for

Rider VBA or a similar decoupling mechanism as the Utilities would be required to move customers to a tier that may differ from that for which the tiered rate and assumed revenue requirement recovery were based. NS-PGL Ex. VG-2.0 Rev. at 17.

Accordingly, the Utilities maintain that the tiered rate proposal is conceptually and practically flawed and should not be adopted.

(2) AG

Peoples Gas' and North Shore's existing rate design promotes inequitable collection of gas costs, the inefficient use of gas commodity and the inefficient use of its distribution and storage networks. Unfortunately, the Companies' new proposal offers little improvement to these ill-advised policies. Under their existing rate structures, Peoples Gas and North Shore recover most of their demand-related costs from customers who use the least amount of gas. As a consequence, customers who use the most gas and cause the greatest residential demands are being subsidized by lower-use customers and customers who use gas more efficiently throughout the year. AG/CUB/City Ex. 2.0 at 3. In addition, customers whose usage is the most volatile throughout the year and who impose the greatest costs on the Companies' gas distribution and storage networks pay the least toward those costs. *Id.* at 6-10. Customers are also impacted by the Companies' use of a steeply declining block charge, which penalizes customers for conserving gas and trying to control their energy bills. *Id.*

The new rate design proposal from the Companies perpetuates these inequities and even compounds them by seeking a 50% increase in the customer charge for residential customers -- an increase even greater than the overall increase in revenue requirement they seek for the residential classes -- but implements a smaller increase for "Choices for You" customers. *Id.* at 10, 15.

AG/CUB/City assert that their proposal represents a first step toward reversing those perverse effects. It does so through a tiered rate structure designed to improve the Companies' ability to recover their fixed costs and also enhance the fairness of the residential rate structure. Although the AG/CUB/City tiered rate structure is specifically designed to result in a more equitable cost recovery, AG/CUB/City also present an alternative rate structure intended to recover demand-related costs equitably from all residential customers. Under this alternative plan, demand-related costs would be collected on a per therm basis, so that an individual customer's contribution to revenues needed to recover the companies' demand-related fixed costs will reflect a customer's actual gas consumption.

Under the Companies' current rate structure, the less efficiently a customer uses gas, the lower his or her annual bill. That is, the more a customer's gas consumption is concentrated in a few months (usually the winter months), the more costs that customer imposes on the distribution and storage system -- yet the lower his or her bill. This is largely due to the Companies' steep declining block distribution rates, which reward inefficient usage by charging customers less per therm for higher gas usage.

In addition to this disparity in cost allocation between even and uneven annual usage, Rubin also pointed out how the Companies' rate design unfairly impacts customer bills by collecting demand-related costs through the customer charge. As Rubin notes, demand related costs are much more closely related (although not perfectly correlated) to gas consumption than to the mere fact that a customer is connected to the system, and therefore the more reasonable way to recover these costs is through a per therm charge. *Id.* at 14.

In order to address the inefficiencies and unfairness inherent in the Companies' existing and newly proposed rate structures, Rubin used billing data provided by Peoples Gas and North Shore to design seven usage tiers based on existing rates for both utilities. AG/CUB/City Ex. 2.0 at 31. The tiered rates would then be increased by an equal percentage to recover the residential class's portion of any rate increase authorized by the Commission. Tiered rates are flat rates -- the customer pays the same distribution charge each month. Under this structure, per therm distribution charges would be eliminated in favor of a system that better reflects differences in the cost of service for each customer (volatile usage increases distribution costs) and is consistent with customers' expectations concerning the different value they place on gas service (some customers use gas only for heating, and then mostly in the winter, which also increases distribution costs).

The AG/CUB/City proposal is not a radical proposal. It incorporates some of the principles used to structure cable television rates. As with cable service, some customers rely on gas service extensively for a variety of uses; others use it very little. Since customers have different needs for natural gas service, and those different needs impose different costs on the gas distribution system, tiered rates can reflect those differences. And as is true with cable service, while much of the cost of providing service is fixed, there are significant differences in the costs inherent in serving customers who consume service more erratically than others.

Rubin's tiered rates would result in lower bills for customers who use gas efficiently throughout the year, compared to existing rates, consistent with principles of cost-causation. On the other hand, customers who use gas less efficiently, i.e., whose usage is disproportionately concentrated in the winter months, would see their annual bills increase because they would lose the benefit of very low second block rates.

The AG notes that the bill impacts of this proposal are significant. Under tiered rates, more than 70% of Peoples customers and more than 80% of North Shore customers would pay lower annual bills than they would pay under the Companies' proposed rates (assuming the same consumption as in the year ending June 2008). *Id.* at 42.

In addition, the AG asserts that there are numerous benefits to tiered rates for regulators trying to design rates that recover fixed costs without penalizing low use customers:

- Tiered rates disconnect revenues from sales, a goal which the utility companies have attempted to pursue through decoupling. Unlike decoupling, however, tiered rates do not penalize customers for conserving energy by triggering automatic rate increases for individual customers when average customer class consumption declines.

- Tiered rates eliminate the need for Rider VBA and the burdens associated with reconciliation proceedings, as well as the unfairness inherent in adjusting rates outside of a rate case context.
- Tiered rates require those whose higher gas usage places greater demands and costs on the distribution system to pay higher rates, while encouraging customers whose usage is near the top end of the tier to have an incentive to keep their consumption down.
- Tiered rates would also do away with the need to project residential consumption in therms and weather normalization would not be needed. Instead, the Commission would only need to determine the number of customers in each usage tier.
- Tiered rates better match demand-related costs and revenues from residential customers by requiring customers who use more gas and place higher demands on the system to pay more than customers who use less gas. *Id.*

Peoples Gas and North Shore raise the strawman argument that Rubin's data renders his proposal "flawed." Yet any flaws in the data set are only the result of the Companies' unwillingness to provide Rubin with the data he originally requested. Rubin asked for customer usage information from January 2006 through December 2008 for each Utility, but the Utilities indicated that they were able to provide this type of data only for a subset of customers (representing approximately two-thirds of all residential customers at each company) for a specific 12-month period. Nevertheless, Rubin's analysis is anything but perfunctory: it is based on actual billing data for approximately 531,000 Peoples Gas residential customers and approximately 104,000 North Shore residential customers for the 12 months from July 2007 through June 2008.

The other category of criticisms the Companies level at Rubin's proposal are described as "practical," and do not provide a principled reason for ignoring the underlying defect in the existing and proposed rate structures which Rubin identifies. Any novel approach to rate design carries with it implementation issues, and in this case, they appear to be the sort that are easily enough addressed by the Companies themselves: the proposal "includes only one set of rates" for both sales and transportation customers; it "would require substantial modifications to the Utilities' customer information systems"; it doesn't take into account the "transition period needed to develop, test and implement the modifications"; it would make revenue forecasting "complicated" and raise "novel issues" regarding tier placement. Utilities IB at 157-158. All of these are technical issues, not policy dilemmas.

Moreover, implementation of tiered rates, because it does away with per therm distribution charges, addresses the issue identified by Staff as a source of conflict with the Companies' customer charge proposal. Staff indicates it cannot support the Companies' attempt to recover its fixed costs through the increased customer charge given the existence of Rider VBA. As Staff correctly points out, the rationale behind Rider VBA is the same as that presented to justify the customer charge increase: to better recover the Companies' fixed costs. Staff IB at 160, 164. Instituting tiered rates addresses this problem directly: it establishes just one charge for fixed cost recovery and also eliminates the irrational price signals that decoupling sends to customers trying to conserve energy.

For all of the reasons noted above, Mr. Rubin's reasonable and efficient tiered rate proposal for residential customers is more efficient, fair and reasonable than the Company's flawed proposals, and should be adopted by the Commission.

(3) Commission Analysis and Conclusion

The Commission rejects the AG's proposal to implement tiered rates. The AG argues that tiered rates would eliminate the need for Rider VBA. Although not entirely clear, it appears that the tiered rate proposal would greatly reduce the costs subject to Rider VBA. The Commission finds that now, while Rider VBA is in place and being reviewed, is not the time to institute new rates that would make that review impractical. Rider VBA will be in place until 2012 and the Commission sees no reason to disrupt it prior to that time. The implementation issues raised by the Utilities solidify our decision to reject the proposed tiered rates and continue with the Rider VBA pilot.

c) Demand Rates

(1) Utilities

The Utilities state that Mr. Rubin's demand-based proposal is less problematic than his tiered rate proposal but is inferior to the Utilities' proposal. They also note that this proposal pushes more of the Utilities' revenues toward the end block of the distribution charges, which is the block most affected by weather variations. As a result, there is a greater need for a decoupling mechanism, such as Rider VBA, with this type of rate. As with the tiered rate proposal, he assumed that charges would not be differentiated among sales and transportation customers and did not factor in revenues or credits arising from the Utilities' transportation program when developing his rates. NS-PGL Ex. VG 2.0 Rev. at 27-28.

The Utilities assert that the AG's proposal would also adversely affect high use customers. For Peoples Gas, the low annual bill increase would be the same, about $60 under Peoples Gas' and Mr. Rubin's proposals. The mean annual bill increase would be similar, with Mr. Rubin's proposal resulting in a $149 annual bill increase compared to $148 arising from Peoples Gas' proposal. However, the high annual bill increase under Mr. Rubin's demand-based rates proposal would be $1,886 compared to $1,495 under Peoples Gas' proposal, or about 26% higher. For North Shore, the low annual bill increase would be similar, at about $66 under Mr. Rubin's proposal and $68 under North Shore's proposal. The mean annual bill increase would be similar, with Mr. Rubin's proposal resulting in a $123 annual bill increase compared to $120 arising from North Shore's proposal. However, the high annual bill increase under Mr. Rubin's demand-based rates proposal would be $1,862 compared to $825 under North Shore's proposal, or 126% higher. NS-PGL Ex. VG-2.0 Rev. at 29-30.

Finally, Mr. Rubin proposed to recover all demand-related costs on an equal cents per therm basis for both the first and second blocks. This incorrectly infers that demand-related costs are volumetrically based. The Utilities proposed an average and peak methodology to allocate demand-related costs in their ECOSSs, under which most costs are allocated to each rate class based on peak day usage and a lesser amount is allocated based on average usage. The resulting rate design should consider how underlying costs are reflected in the Utilities' supporting cost studies. Demand-related costs are fixed, and there are a few acceptable methodologies for recovering such costs. The Utilities believe that absent a fixed demand charge, such fixed costs should be recovered through a fixed charge such as the customer charge, or spread between the customer and commodity charges. *Id*. at 31-32.

While less problematic than the tiered rate proposal, the demand rate proposal has flaws not present in the Utilities' proposal and should be rejected.

(2) AG

If the Commission does not adopt tiered rates, the AG asserts that the Utilities should be directed to collect demand related costs on a per therm basis to better reflect cost causation principles. Under this alternative plan, demand-related costs would be collected on a per therm basis, so that an individual customer's contribution to revenues needed to recover the Companies' fixed costs will reflect a customer's actual gas consumption. The Companies' demand-related costs for residential customers are approximately 15.831 cents per therm for Peoples and 10.741 cents per therm for North Shore. AG/CUB/City Ex. 2.01. The AG notes that these demand-related costs are higher than the existing second block charge for each company (10.580 cents and 6.356 cents for Peoples and North Shore, respectively). AG/CUB/City Ex. 2.0 at 5, Table 1. Thus, the Companies' existing rate structure – as well as its proposed rate structure – require lower-usage customers (those who do not use more than 50 therms in a month) to subsidize the demand-related costs for higher-use customers.

Instead of increasing rates in the second block to at least recover these demand-related costs, the Companies propose to treat demand-related costs as a "customer" cost – that is, as an amount that does not vary with the amount of gas a customer uses. The AG asserts that it is not credible to assert that a non-heating customer in a small apartment should be responsible for the same amount of demand costs as a heating customer in a large, single-family house.

But that is the Companies' proposal – to recover demand costs by an equal amount for each customer. The Companies calculate that the amount would be $12.38 per month per customer for Peoples Gas (Peoples Gas Ex. VG-1.5) and $11.14 per month per customer for North Shore (North Shore Ex. VG-1.5). The AG submits that the Companies' proposal must be rejected. If the Commission does not adopt the Peoples' tiered rate proposal, then at a minimum the residential rates must be designed to recover demand-related costs on a per-therm basis. This would be much more equitable than the Companies' proposal to recover such costs on a per-customer basis.

The resulting rates, under the Companies' proposed revenue requirement, are shown in the following table. AG/CUB/City Ex. 2.02 shows the derivation of these rates, and provides a simple methodology to recover demand-related costs at a lower revenue requirement than the Companies requested.

Table 4. Demand-Based Residential Rates Under Companies' Proposed Revenue Requirement		
	Peoples Gas	North Shore
Customer charge	$23.30	$19.90
First 50 therms	35.954¢	24.221¢
All over 50 therms	16.787¢	11.012¢

AG/CUB/City Ex. 2.0 at 15.

While the AG's proposed demand rates do not eliminate all of the disparity that the AG's tiered rate proposal would address, this approach to rate design makes substantial progress toward developing cost-based residential rates and sending residential customers the appropriate price signals. Accordingly, the AG asserts that the rate design proposed by Peoples Gas and North Shore should be rejected in favor of the more efficient and equitable rate design recommended by the Attorney General, the Citizens Utility Board and the City of Chicago.

(3) Commission Analysis and Conclusion

Mr. Rubin testified that "[d]emand-related costs are those that vary with the maximum usage that a customer places on the system. Demand-related costs are reflected in the sizing of distribution mains, storage facilities, and other types of distribution facilities and related operations and maintenance costs." AG/CUB/City Ex. 2.0 at 12. Mr. Rubin incorrectly states that, currently, and under the Utilities' proposal, demand-related charges do not vary with the amount of gas a customer uses. In fact, the Utilities' proposal would result in demand–related costs being recovered through the distribution charges.

We also note the rebuttal testimony of Utilities witness Grace citing the Gas Distribution Rate Design Manual Prepared by the National Association of Regulatory Utility Commissioners ("NARUC") Staff Subcommittee on Gas (June 1989), which states that:

> the most controversial issue is deciding where capacity costs belong in the rate. Because they are fixed costs, it is sometimes argued that they should be part of the customer charge. On the other hand, it can be argued that … those common fixed costs should be recovered evenly from all units of commodity sold. It is even occasionally proposed that these costs be spread between customer and commodity charges.

NS-PGL Ex. VG-2.0 at 32.

We find compelling Ms. Grace's explanation that demand costs (also known as capacity costs) are fixed costs and not volumetrically based. Notwithstanding the fixed nature of these costs, demand-related costs are allocated to customer classes based upon the respective customer classes' contribution to overall demand. Therefore, they reflect customers' respective demands on the system. However, rather than recovering these costs through a fixed demand charge (e.g., $50 for 0 to 1000 therms of demand, $100 for 1001 to 2000 therms, etc.), the Utilities' proposals place recovery of these costs in the distribution charge and recover them through volumetric charges on a per therm of usage basis, not a demand basis. We conclude that it is reasonable, in the interests of gradualism and rate continuity, to recover demand costs in the manner proposed by the Utilities and to retain the declining two-block distribution rates with the allocation between blocks as proposed by the Utilities.

C. Tariffs – Other Tariff Issues

1. Uncontested Issues – North Shore and Peoples Gas

a) General Terms and Conditions

(1) The Record

The Utilities each proposed several changes to their Terms and Conditions of Service. Those changes are: (1) revise the service activation and reconnection charges; (2) insert a specific date for grandfathering the second pulse charge; (3) revise language related to the "Correction for Pressure, Temperature and/or Supercompressibility" to be consistent with the Utilities' practices concerning the pressure at which customers are served; (4) add a definition of "person" related to changes to Riders 4 and 5; and (5) eliminate Peoples Gas' Facilities Charge. NS Ex. VG-1.0 Rev. at 28; PGL Ex. VG-1.0 Rev. at 30.

(2) Commission Analysis and Conclusion

The proposed changes to the Terms and Conditions are discussed in more detail below. The changes are fully supported in the record and neither Staff nor any party opposed them. The Commission finds the changes are just and reasonable and approves them.

b) Service Activation Charges

(1) The Record

North Shore performs two types of service activation: succession turn-on when a customer moving out discontinues gas service at approximately the same time as a new applicant requests service; and a straight turn-on when there has never been service at a premises or there has been a longer time lapse between customers. North Shore performed a cost study (NS Ex. VG-1.9) showing that the cost for a succession turn-on is $16.59 and proposed, in response to a Staff proposal, to charge $16.50; for a straight turn-on the cost is $43.91 and proposed to charge $35; and for lighting each appliance in excess of four the cost is $8.91 and proposed no change to its current $5 charge. NS Ex. VG-1.0 Rev. at 24; NS-PGL Ex. VG-2.0 Rev. at 49.

Peoples Gas performs the same types of service activations. Its cost study (PGL Ex. VG-1.9) showed the cost for a succession turn-on is $15.52 and proposed to charge $15; for a straight turn-on the cost is $47.78 and proposed to charge $25; and for lighting each appliance in excess of four the cost is $10.67 and proposed no change to its current $5 charge. PGL Ex. VG-1.0 Rev. at 26.

Staff witness Boggs reviewed the proposed charges and, with one proposed revision, he recommended their approval. He also recommended that, in future rate cases, the Utilities should move steadily to full cost recovery from the customers who cause these expenses. Staff Ex. 11.0 at 3-8, 25-28; Staff Ex. 25.0 at 2.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed service activation charges are each based on a cost of service study and, while some of the charges continue to be set below cost, the Utilities are moving the charges closer to cost. The Commission agrees with Staff that the Utilities should continue, in future rate cases, to move the charges steadily closer to cost. The Commission finds that the proposed service activation charges are just and reasonable and, therefore, approves them.

c) Service Reconnection Charges

(1) The Record

North Shore performs three types of service reconnection: basic reconnections requiring only a meter turn-on; reconnections requiring setting a new meter; and reconnections at the main. North Shore performed a cost study (NS Ex. VG-1.9) showing that the cost for a reconnection at the meter is $65.88 and proposed to charge $60; for a reconnection when the meter is reset the cost is $256.04 and proposed to charge $125; and for a reconnection at the main the cost is $1,988.89 and proposed to charge $350. The cost to light additional appliances is $8.91, and proposed no change to the current $5 per appliance in excess of four charge. NS Ex. VG-1.0 Rev. at 24-25.

Peoples Gas performs the same three types of service reconnection, and it also preformed a cost study (PGL Ex. VG-1.9). The study showed that the cost for a reconnection at the meter is $78.59 and proposed to charge $60; for a reconnection when the meter is reset the cost is $228.91 and proposed to charge $125; and for a reconnection at the main the cost is $2,189.49 and proposed to charge $350. The cost to light additional appliances is $10.67, and proposed no change to the current $5 per appliance in excess of four charge. PGL Ex. VG-1.0 Rev. at 26-27.

Staff witness Boggs reviewed the proposed charges, and he recommended their approval. He also recommended that, in future rate cases, the Utilities should move steadily to full cost recovery from the customers who cause these expenses. Staff Ex. 11.0 at 8-12, 28-32.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed service reconnection charges are each based on a cost of service study and, while some of the charges continue to be set below cost, the Utilities are moving the charges closer to cost. The Commission agrees with Staff that the Utilities should continue, in future rate cases, to move the charges steadily closer to cost. The Commission finds that the proposed service reconnection charges to be just and reasonable and, accordingly, approves them.

d) Second Pulse Capability

(1) The Record

The Utilities proposed no change to the $14 monthly second pulse capability charge. NS Ex. VG-1.0 Rev. at 28; NS Ex. VG-1.1 at 10; PGL Ex. VG-1.0 Rev. at 30; PGL Ex. VG-1.1 at 12. Second pulse capability is an optional service and involves measurement devices that can provide real time usage data to customers. The charge does not apply to those who had the capability installed prior to February 14, 2008 (the effective date of the new tariffs approved in the Utilities' 2007 rate cases). Staff supported the wording change to add this date. Staff Ex. 11.0 at 12-13.

(2) Commission Analysis and Conclusion

There is no evidence for changing the existing second pulse charge. The Commission approves retention of the existing second pulse charge and addition of the specific date that determines whether a customer owes the charge.

e) Rider 1

(1) The Record

The Utilities proposed editorial changes to Rider 1, Additional Charges for Taxes and Customer Charge Adjustments, to clarify the rider. NS Ex. VG-1.1 at 16; PGL Ex. VG-1.1 at 19. Staff recommended approval of the changes. Staff Ex. 11.0 at 14-15, 37.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed charges are editorial in nature and will clarify the rider. The Commission approves these changes.

f) Rider 2

(1) The Record

The Utilities proposed several editorial changes to Rider 2, Gas Charge, to clarify the rider. The Utilities propose deleting references to riders and service classifications that they propose to delete. For Peoples Gas, the Utilities propose to eliminate a date reference that is no longer needed. NS Ex. VG-1.0 at 28; PGL Ex. VG-1.0 at 31. Staff recommended approval of the changes, if the Commission approves elimination of the referenced tariffs. Staff Ex. 11.0 at 15-16, 38. Neither Staff nor any party opposed removal of the referenced tariffs.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed changes are editorial in nature and will clarify the rider. The Commission approves these changes.

g) Riders 4 and 5

(1) The Record

The Utilities proposed revisions to Rider 4, Extension of Mains, and Rider 5, Service Pipe, to accommodate situations where the person or group of persons requesting the main or service is developing the property for future gas service and is not the applicant for service. NS Ex. VG-1.0 at 28-29; PGL Ex. VG-1.0 at 32. Staff recommended approval of the changes. Staff Ex. 11.0 at 16-19; 38-41.

(2) Commission Analysis and Conclusion

The Commission agrees with Staff and the Utilities that it is reasonable to address situations where someone other than an applicant for service, for example, a developer, is requesting a main or service installation. Accordingly, the Commission approves the changes to Riders 4 and 5 to accommodate this circumstance.

h) Account 385 Facilities Charge

(1) The Record

Peoples Gas proposed to eliminate the Facilities Charge. In its last rate case, the Commission ordered Peoples Gas to directly bill the small number of customers served by large meters that are classified under Account 385 ("Industrial Measuring and Regulating Station Equipment"). Subsequent to its last rate case, Peoples Gas stated that it changed certain accounting policies, resulting in 781 customer accounts being reclassified under Account 385, which far exceeds the number at issue in the 2007 rate case. Also, Peoples Gas explained that it is proposing a meter class 3 for its S.C. No. 2 that would better assign the Account 385 costs. PGL Ex. VG-1.0 Rev. at 31; NS-PGL Ex. VG-2.0 Rev. at 50. Staff agreed that the charge should be eliminated. Staff Ex. 11.0 at 36; Staff Ex. 25.0 at 2-3.

(2) Commission Analysis and Conclusion

The Commission agrees that the facts underlying its decision in the last rate case to require a specific Facilities Charge have changed. In particular, the introduction of a new meter class will address our concern that costs be allocated to the customers causing their incurrence.

2. Volume Balancing Adjustment (Rider VBA)

The Commission approved decoupling mechanisms (Rider VBA, Volume Balancing Adjustment) for the Utilities in their last rate cases. Rider VBA is in effect for a four-year pilot period that will end with the March 2012 filing, unless the Utilities request and receive approval to make the rider permanent. *Peoples 2007* at 152. The Utilities proposed no changes to Rider VBA in this proceeding, but the "rate case margins" components of the calculation will change. NS Ex. VG-1.0 Rev. at 14, 19-20; PGL Ex. VG-1.0 Rev. at 15, 21. At the time of the filing, for the period May 2008 through February 2009, North Shore had refunded $475,000 to S.C. No. 1 customers and $397,000 to S.C. No. 2 customers. NS Ex. VG-1.0 Rev. at 14, 20. For Peoples Gas, the refunded amounts were $1.7 million to S.C. No. 1 customers and $2.3 million to S.C. No. 2 customers. PGL Ex. VG-1.0 Rev. at 16, 21.

a) Establishment of new margins

(1) The Record

When new rates are set in these proceedings, the "rate case margins" ("RCM") will change. Because the Commission accepts the Utilities' proposal to differentiate for gas cost-related Account 904 costs in the customer charge, there will be a new RCM for each of S.C. Nos. 1 and 2. If the Commission requires differentiation in the distribution charge, there will be four new RCMs, namely, a sales RCM and a transportation RCM for each of S.C. Nos. 1 and 2. NS Ex. VG-1.0 Rev. at 14, 19-20; PGL Ex. VG-1.0 Rev. at 15, 21. The Utilities provided, in data responses, the revised RCM and "rate case customers," based on their direct cases (Staff Ex. 1.0 at 44 and Att. A) and their rebuttal cases (Staff Ex. 15.0 at 35 and Att. H). The Utilities stated that they will provide the Commission with final RCMs, based on the approved distribution charges, with their compliance filings. NS-PGL Ex. VG-2.0 Rev. at 5.

(2) Commission Analysis and Conclusion

The Commission agrees that there will be new Rider VBA RCMs resulting from these rate cases. The "rate case customers" component of the calculation will also change as a result of these cases. The Commission directs the Utilities to include these new RCMs with their compliance tariffs. The new RCM compliance filings shall be publicly filed on the Commission's e-Docket system.

b) Change in Annual Report (Uncontested)

(1) The Record

Staff witness Hathhorn discussed a requirement from the last rate case Order that Staff provide the Commissioner an annual report on the Utilities' rates of return and Rider VBA's effect on the return. *Peoples 2007* at 152. She recommended that the Utilities, rather than Staff, prepare this report. Staff Ex. 1.0 at 45. The Utilities agreed. NS-PGL Ex. VG-2.0 Rev. at 53-54.

(2) Commission Analysis and Conclusion

The Commission agrees that it is reasonable for the Utilities to prepare this report. The Commission directs the Utilities to prepare and submit the required report to Staff and the Commission at the time the Utilities file their petition to initiate a reconciliation proceeding.

D. Bill Impacts

1. The Record

The Utilities prepared detailed bill impact analyses, for all service classifications affected by its rate proposals, at various usage levels under present and proposed rates. NS Exs. VG-1.0 Rev. at 23 and VG-1.8; PGL Exs. VG-1.0 Rev. at 25 and VG-1.8. The Utilities also provided additional analyses for the impact on S.C. No. 1, Small Residential Service, customers. NS Exs. VG-1.0 Rev. at 17 and VG-1.6; PGL Exs. VG-1.0 Rev. at 18 and VG-1.6. The Utilities' proposed rate designs and the resulting bill impacts are consistent with the objectives of continuity and gradualism. NS Ex. VG-1.0 Rev. at 1-2; PGL Ex. VG-1.0 Rev. at 1-2.

2. Commission Analysis and Conclusion

The Commission finds that the bill impact information prepared by the Utilities and discussed by the Utilities and Staff lend support to the rates that the Commission is approving in this proceeding. The bill impact studies were adequate and sufficient for this purpose.

XIII. Transportation Issues

A. Overview

In their 2007 rate cases, the Utilities proposed extensive changes to their transportation programs. The Utilities' proposals engendered extensive testimony, and the Commission ultimately approved several major changes to the programs. *Peoples 2007* at 268-287. The Utilities implemented the substantially revised large volume transportation riders on August 1, 2008. The Utilities concluded that it would be more beneficial to gain experience under the new riders rather than to propose any new modifications at this time. NS Ex. VG-1.0 Rev. at 30; PGL Ex. VG-1.0 Rev. at 33. The Utilities also significantly revised their small volume program in the 2007 rate cases and implemented the changes in 2008. Consequently, the Utilities proposed no substantive changes in these cases. NS-PGL Ex. JM-1.0 at 15. As with the proposed changes to the large volume programs, there was considerable testimony concerning the small volume programs, and the Commission ruled on several proposals by both the Utilities and intervenors. *Peoples 2007* at 268-272, 287-307.

The Utilities proposed no operational changes to their transportation programs. Staff and intervenors proposed changes to the large volume program, all but one were uncontested.

B. Uncontested Issues

1. Elimination of Transportation Transition Riders

a) The Record

The Utilities implemented extensive changes to their transportation programs in their last rate cases. There was a transition period, with transition riders, before the changes took effect. Those transition riders were called Riders FST-T, SST-T, LST-T, TB-T (Peoples Gas only) and P-T. As of August 1, 2008, no customer or supplier was receiving service under the transition riders, and the Utilities proposed to eliminate them. No party opposed these proposals.

b) Commission Analysis and Conclusion

The Commission agrees that because no customers take service under these transition riders, it is appropriate to eliminate them from the Utilities' tariffs.

2. Riders FST, SST, and P Charges

a) The Record

The Utilities prepared cost studies to support the administrative charges under their transportation programs. NS Ex. VG-1.10; PGL Ex. VG-1.10. Based on its study, North Shore proposed to reduce its Riders FST and SST Administrative Charge from \$8.94 to \$7.32 per account and its Rider P Pooling Charge from \$4.95 to \$3.44 per account. NS Ex. VG-1.0 Rev. at 26. Based on its study, Peoples Gas proposed to reduce its Riders FST and SST Administrative Charge from $11.24 to $9.87 per account and its Rider P Pooling Charge from $8.36 to $6.97 per account. PGL Ex. VG-1.0 Rev. at 28. Neither Staff nor any party opposed these proposals.

b) Commission Analysis and Conclusion

The proposed charges are the result of a specific cost of service study. The Commission finds that the study supports the proposed charges and approves these charges.

3. Intra-Day Nomination Rights

a) The Record

Utilities witness McKendry explained that the current nomination deadline is 11:30 a.m. the day prior to the gas day (the "timely" cycle). Customers may also reallocate the nominated quantities at later times. NS-PGL Ex. JM-1.0 at 6-8. The Utilities, citing operational and administrative concerns, offered an alternative to CNE-Gas' proposal that they offer four nomination cycles. NS-PGL Ex. JM-1.0 at 6-12; NS-PGL Ex. RD-1.0 Rev. at 20-25.

For a four-year trial period, the Utilities will offer a late nomination ("Evening Cycle Nomination"). The customer or its supplier must make the nomination no later than 3:00 p.m. on the business day prior to the gas day on which it is to be effective. Unlike timely nominations, which are available every day, the new nomination right would only apply to nominations on business days. The Utilities, by 2:00 p.m., would post on their PEGASys™ system the aggregate volume the Evening Cycle Nomination may not exceed. Except for Critical Days, the minimum quantity available (increases and decreases) would be 100,000 therms for Peoples Gas and 20,000 therms for North Shore. On Critical Supply Surplus Days, the Utilities will allow no increases. On Critical Supply Shortage Days, the Utilities will allow no decreases. The Utilities may also post separate quantities that apply to the allowable increases and decreases, *i.e*., increases of no more than X and decreases of no more than Y. The Utilities would reduce, *pro rata*, transportation customer Evening Cycle Nominations in excess of the posted available quantities. NS-PGL Ex. RD-1.0 Rev. at 24.

In response to CNE-Gas' proposal that the Utilities not change their current practices that allow changes to nominations when an upstream supplier cuts a transportation customers' gas (CNE-Gas Ex. 2.0 at 4-5), Utilities witness McKendry agreed that the current practice will continue. NS-PGL Ex. JM-2.0 at 3-4. The Utilities agreed to include tariff language describing this practice of revising timely nominations to address supply cuts.

b) Commission Analysis and Conclusion

The Commission agrees that adding an additional nomination cycle may be helpful to the Utilities' transportation customers and suppliers. The Commission recognizes that it adds some complexity to the Utilities' administrative processes and its gas supply activities, and the record does not support requiring the addition of three new nomination cycles in light of that added complexity. However, the Utilities have determined that they can offer one additional nomination cycle and the potential benefits to customers make this a worthwhile service to offer for a trial period. Accordingly, the Commission approves the proposed Evening Nomination Cycle, effective for a four-year trial period, and directs the Utilities to include language in their tariffs to describe the terms and conditions of this nomination right as well as the current practice related to handling nomination changes required by upstream cuts.

4. Storage Credit

a) The Record

Staff witness Sackett questioned why CFY suppliers, but not large volume transportation customers, receive a credit based on the Utilities' savings from reduced storage inventory requirements arising from transportation customers filling their Allowable Bank inventory. Staff Ex. 12.0R at 21. The Utilities agreed that a credit for the Riders FST and SST customers would be appropriate. Ms. Grace testified that the credit for S.C. No. 2 customers would differ from the large volume demand service classifications, S.C. No. 3 (North Shore) and S.C. No. 4 (Peoples Gas) because storage costs for S.C. No. 2 are fully bundled in base rates and this is not the case for the large volume demand rates. The Utilities proposed that, for Rider FST, the credit would be per therm of Maximum Daily Quantity ("MDQ"). For Rider SST S.C. No. 2 customers, the base rate credit amount credit would be per therm of MDQ and the gas charge credit amount would be per therm of Selected Standby Quantity ("SSQ"). For the Rider SST large volume demand service classifications, the credit would be per therm of SSQ. NS-PGL Exs. VG-2.0 Rev at 55-57; VG-2.5N; VG-2.5P. Ms. Grace also stated in response to Mr. Sackett that the CFY credit would be per therm of MDQ, rather than the current method of including it as a credit against the Aggregation Charge. NS-PGL Ex. VG-2.0 Rev at 64-65.

b) Commission Analysis and Conclusion

The Commission agrees with Staff that a credit similar to what already exists for the small volume transportation program is appropriate for the large volume program. The Utilities proposed a reasonable, cost-based way to develop and implement the credit. The Commission finds that the Utilities' proposal is reasonable and approves it as well as the change in the CFY credit to a credit per therm of MDQ.

5. Diversity Factors

a) The Record

Staff witness Sackett recommended that the Utilities update their Riders FST and SST diversity factors based on the most recent four years' data. Staff Ex. 12.0R at 25. Peoples Gas agreed to reduce its diversity factor from 0.87 to 0.86, and North Shore agreed to reduce its diversity factor from 0.75 to 0.73. NS-PGL Ex. VG-2.0 Rev. at 55.

b) Commission Analysis and Conclusion

The Commission agrees with Staff that the diversity factors should be updated. The Staff proposal, to which the Utilities agreed, correctly states what the new factors should be, and the Utilities should use these factors in the relevant calculations in their tariffs.

6. Standby Commodity Charge

a) The Record

Staff witness Sackett proposed that the Standby Commodity Charge ("SCC") be set at a Chicago citygate price to prevent arbitrage. He stated that the current SCC calculation allows transportation customers to "arbitrage the difference" between the SCC and the Chicago citygate price. Staff Ex. 12.0R at 42. The Utilities agreed with this proposal. The Utilities stated that Rider FST customers' usage is not daily metered, so the calculation would use an average price for the month, namely the existing definition of Average Monthly Index Price. Rider SST customers' usage is daily metered, so the calculation would use a daily price applicable to the flow date on which the imbalance occurred. An appropriate definition (Daily Index, Midpoint) is in Rider AGG. The Utilities proposed to revise Riders FST and SST to define the SCC price consistent with the existing definitions. NS-PGL Ex. RD-1.0 Rev. at 19-20. The Utilities also noted that the SCC is used in Rider P. NS Ex. VG-1.1 at 60; PGL Ex. VG-1.1 at 70.

b) Commission Analysis and Conclusion

The Commission agrees with Staff's recommendation. As Mr. Sackett explained, tying the SCC to a Chicago citygate price may reduce price arbitrage that could be detrimental to sales customers. The Utilities' specific proposals for the indices and definitions are reasonable. The Commission directs the Utilities to include the necessary language in Riders FST, SST, and P to define the SCC consistent with their proposals.

7. Maximum Daily Quantity (MDQ) Calculation

a) The Record

RGS witness Crist disputed the Utilities' calculation of the MDQ for CFY customers. RGS Ex. 1.0 at 31. Mr. McKendry explained that the Utilities round the MDQ calculation to the nearest dekatherm, but agreed to round to the nearest therm. NS-PGL Ex. JM-1.0 at 23. The Utilities noted that the changed method applies to the large volume transportation program, which has an MDQ calculation. NS Ex. VG-1.1 at 38, 48; PGL Ex. VG-1.1 at 43, 53.

b) Commission Analysis and Conclusion

The Commission agrees with RGS that, especially for small usage customers, it is more accurate to round the MDQ calculation to the nearest therm. The Commission approves this proposal for the large and small volume programs and directs the Utilities to make any necessary changes to their tariffs.

8. Rider SST Unbundled Allowable Bank

a) The Record

Staff witness Sackett proposed that the Utilities unbundle their Rider SST Allowable Bank from the standby service. Staff Ex. 12.0R at 25-42; Staff Ex. 26.0 at 7-43. The Utilities did not accept Staff's proposal to unbundle the Rider SST Allowable Bank from standby service, citing operational, administrative and rate concerns. NS-PGL Exs. RD-1.0 Rev. at 2-17; RD-2.0 at 2-13; VG-2.0 Rev. at 57-58; VG-3.0 at 30-36. In response to a data request, the Utilities agreed to work collaboratively with Staff, prior to filing their next rate cases, to develop proposals for unbundling standby and storage services that are provided to S.C. Nos. 2 (North Shore and Peoples Gas), 3 (North Shore), and 4 (Peoples Gas) customers under Riders FST and SST. The Utilities would file proposed tariff changes to implement any resulting mutually acceptable proposals, and, if and to the extent such proposals are not developed, to address such unbundling in their next rate case filings. Staff Cross Grace Exs. 5 and 6.

In its Brief on Exceptions, CNE-Gas states that soliciting input from interested Transportation Customers and their marketers on any storage unbundling proposals could result in less opposition to proposals that are offered in the next rate cases, as objections and concerns could be addressed prior to filing. CNE-Gas requests solicitation of input and/or feedback from interested stakeholders

b) Commission Analysis and Conclusion

The Commission agrees that it is reasonable for the Utilities to work with Staff and all other interested stakeholders to develop reasonable proposals for unbundling storage service. The Commission finds that the Utilities should file any agreed upon proposals in their next rate cases. To the extent Staff, participating stakeholders and the Utilities do not reach agreement, the Utilities should address this matter in those rate cases.

9. Elimination of Rider TB - Transportation Balancing Service

a) The Record

Peoples Gas proposed to eliminate Rider TB, Transportation Balancing Service. Few customers have taken this service and, currently, no customers are taking it. PGL Ex. VG-1.0 Rev. at 32. Neither Staff nor any party opposed the proposal.

b) Commission Analysis and Conclusion

The Commission agrees that Peoples Gas need not continue to offer this service. The Commission approves Peoples Gas' proposal to eliminate its Rider TB.

C. Large Volume Transportation Program

1. Super Pooling on Critical Days

a) Utilities

The large volume program refers to customers taking service under Rider FST (Full Standby Transportation Service) or SST (Selected Standby Transportation Service). Many of these customers take service from alternative suppliers who "pool" customers under Rider P (Pooling Service). NS-PGL Ex. JM-1.0 at 6. For the large volume programs, Ms. Grace explained that the Utilities implemented new operational provisions following their 2007 rate cases. The Utilities believed it would be more beneficial to gain experience under the revised program than to propose modifications in these cases. The Utilities proposed only updating certain charges based on new cost studies; eliminating transitional riders that were in place as a bridge from the former program to the revised program that the Utilities implemented on August 1, 2008; making editorial changes; updating the number of "base rate" Allowable Bank days; and, for Peoples Gas, eliminating a rider under which customers do not take service. NS Ex. VG-1.0 Rev. at 29-30; PGL Ex. VG-1.0 Rev. at 32-33.

CNE-Gas witness Rozumialski recommended that the Commission require the Utilities to implement super pooling for measuring critical and supply surplus day thresholds. The Commission rejected such "super pooling" as proposed in the Utilities' 2007 rate cases, except for a specific inventory requirement that is determined on one day each year. *Peoples 2007* at 282-283. The Utilities argue that the administrative burden and attendant concerns that the Utilities expressed in the last rate cases have not changed or been alleviated. NS-PGL Ex. JM-1.0 at 13.

They allege that the current proposal does not remove the administrative burden from the Utilities. If a supplier requests a waiver from what CNE-Gas called "penalty charges" based on super pooling, the Utilities will need to ascertain if the request meets the criteria for pooling the accounts or contracts and waiving the charges. Other than being triggered by a request rather than being triggered by a critical day, it is the same burden as rejected in the 2007 rate cases. *Peoples 2007* at 282-283; NS-PGL Ex. JM-1.0 at 13; NS-PGL Ex. JM-2.0 at 4-5.

Also, the Utilities note that the Nicor practice, cited by both Staff and CNE-Gas, was apparently the product of a settlement. In other words, this was an uncontested issue resulting from a settlement.

Staff's conclusion that the Utilities would not be entangled in the supplier/customer relationship is not, the Utilities contend, necessarily true. One element of administering super pooling is to ensure that only the correct pools and stand alone customers are correctly accounted for in the super pool. NS-PGL Ex. JM-1.0 at 14. For example, a customer (likely a stand alone customer not in a pool) may purchase gas from more than one supplier. *See, e.g., Peoples 2007* at 282. If two suppliers seek a waiver based on including the same customer in the "super pool," that could entangle the Utilities in the supplier/customer relationship.

Further, the Utilities argue that the proponents of this proposal have the burden of proof. *Central Illinois Public Service Company v. Illinois Commerce Commission*, 5 Ill. 2d. 195, 211 (1955). According to the Utilities, it is not their burden, as posited by Staff, to show that "they are unable to implement" the proposal. An intervenor proposed changes concerning the small volume program ("Choices For You[sm]" or "CFY"), and the Utilities showed that the intervenor did not meet its burden of supporting changes to the CFY program.

The Utilities argue that it is also not their burden to show "how they differ from Nicor Gas." *Id*. The Commission's task is to set just and reasonable rates for the Utilities based on the record in this proceeding. There is no evidence that the proposal to which Nicor agreed applies to the Utilities' programs. For example, Staff concludes that it is "unnecessary to modify the billing system," (*Id*. at 191) but there is no evidence about whether Nicor modified its billing system or whether the Utilities would need to do so to efficiently implement the proposal.

If the Commission approves "super pooling," the Utilities assert that it must be clear what this entails. Staff likens it to a "billing discrepancy," which may suggest canceling and re-issuing the bill(s) in question and revising all quantities and charges on the bill. CNE-Gas appears to suggest it is requesting only a "credit of penalty charges." A cancel and re-bill that affects only waiving penalties is a very different exercise from a cancel and re-bill that adjusts all quantities and charges.

The Utilities urge the Commission to reject CNE-Gas' super pooling proposal. If it approves the proposal, the Commission should clarify that it is only requiring waiver of penalty charges and it should clarify if stand alone customers (customers not in a pool) may be included in super pools.

b) CNE-Gas

CNE-Gas proposes that Peoples Gas permit Super Pooling on Critical Days, which allows all third party groups, or pools, that are under common management to be balanced in aggregate prior to the application of Unauthorized Usage Charges. Super Pooling is reasonable and equitable because, in aggregate, the supplier has delivered adequate volumes of gas to serve the needs of all of its pools that are under common management – it is only when individual groups are isolated that a certain subset may be under nominated and the penalty charges would apply. CNE-Gas argues that Super Pooling remedies this inequitable situation where a group incurs penalties even though Peoples Gas has not incurred any harm and thus, should not be imposing penalties. If Peoples Gas did not limit group size for pooling purposes, there would be no need for Super Pooling, but Peoples Gas limits Rider P pool size to 300 accounts. Peoples Gas itself is not required to split its usage into subgroups in order to determine if Unauthorized Use occurred. Peoples Gas already applies Super Pooling to winter injection requirements. CNE-Gas Ex. 1.0.

CNE-Gas explains that during a Supply Shortage Day, if under-delivered, a Transportation Customer faces two financial penalties under Peoples Gas' current tariff: (1) a $60 per dekatherm penalty; and (2) Peoples Gas requires the customer to purchase replacement gas from the utility at the Rider 2 Unauthorized Use rate, even if the supplier in the aggregate has provided ample supply of gas for all of its customers served in its various pools. CNE-Gas Ex. 1.0; CNE-Gas Ex. 2.0.

In *Peoples 2007*, the Commission rejected Super Pooling because it “would present the billing system complexity the Utilities reasonably want to avoid” and “would likely and excessively entangle the utilities in the relationship between suppliers and individual customers with respect to allocation of daily gas deliveries.” In this proceeding Peoples Gas continues to object to CNE-Gas’ proposed Super Pooling on Critical Days due to the administrative burden and difficulty in automating the process even though in this proceeding CNE-Gas submitted a materially different proposal, one designed to address the deficiencies for which the Commission rejected Super Pooling in the prior dockets. Peoples Gas’ objection is unfounded because CNE-Gas’ alternative process eliminates the need to make significant billing changes. Staff witness Sackett noted that Peoples Gas ignored CNE-Gas’ current proposal and instead focuses on CNE-Gas’ proposal made in the past rate case. Staff Ex. 26.0.

CNE-Gas asserts that its proposal is consistent with the Commission’s decision in Nicor’s last rate case. This method permits a third party supplier to “apply for a waiver of the penalty portion of the Unauthorized Use Charge on a Critical Day” for its groups, when the third party supplier is able to substantiate that their other “groups have excess deliveries of sufficient quantity to alleviate all, or a portion of, the unauthorized gas condition.” This method alleviates the $60 per dekatherm penalty only when the third party supplier has delivered quantities of gas to meet the needs of its customers. CNE-Gas Ex. 1.0.

Under CNE-Gas’ proposal, third party suppliers apply for a credit of penalty charges when, in aggregate, their other pools have excess deliveries of sufficient quantity to alleviate all, or a portion of, any incremental charges and penalties incurred. Neither PGL nor NS would be responsible for determining or applying Super Pooling on Critical and Supply Surplus Days; the responsibility for Super Pooling determination on Critical and Supply Surplus Days would rest with the third party supplier, as proposed by CNE-Gas. According to CNE-Gas, there would be no need to automate any process, as the Company would not be responsible for programmatically determining and applying Super Pooling to supplier pools. Thus, CNE-Gas asserts that major modifications to the Company billing system are unnecessary and this objection is resolved. CNE-Gas Ex. 2.0.

Peoples Gas’ sole argument against Super Pooling rests in the burden the process places on the utility. In a footnote, Peoples suggested it is unclear as to when Super Pooling applies. As the heading for this issue indicates, “Super Pooling on Critical Days” is the intent of the proposal. According to CNE-Gas, the application of Super Pooling is associated with the financial penalties incurred on a Critical Day, including costs such as Unauthorized Use of Gas penalties and the purchase of unneeded replacement gas, whether occurring on a Supply Surplus or a Supply Shortage day.

CNE-Gas urges the Commission to adopt its Super Pooling on Critical Day proposal as a matter of fairness. If, in aggregate a supplier has delivered total volumes required for its customers, then no harm accrues to the utility if Super Pooling is permitted.

CNE-Gas urges the Commission to adopt its Super Pooling on Critical Day proposal as a matter of fairness. If, in aggregate a supplier has delivered total volumes required for its customers, then no harm accrues to the utility if Super Pooling is permitted.

c) Staff

CNE witness Rozumialski recommended that the Companies allow for incorporation of super-pooling in the calculation of Critical Day penalties as an after-the-fact accounting correction as approved by the Commission in Nicor Gas' last rate case, Docket 08-0383. Super pooling would allow transporters to net over and under deliveries of their customers in order to determine Critical Day charges. In this case, CNE provides CNE Exhibit 2.1 which is a tariff sheet from Nicor Gas Rider 13 Supplier Transportation Service which states:

> In the event a Rider 13 group incurs Unauthorized Use Charges on a Critical Day, the Group Manager may have the right to submit a written request for waiver of the $6 per therm non-purchased gas portion of the Unauthorized Use Charges within fifteen (15) days of the issuance date of the bill. The Group Manager shall provide the Company with written documentation which demonstrates that its other commonly-managed Rider 13 Groups' Critical Day deliveries would have eliminated the Unauthorized Use condition in whole or in part.

CNE proposes here to incorporate that Commission-approved method from Nicor Gas' tariff.

Companies witness McKendry rejected this proposal by raising the same objections that the Companies raised in their 2007 rate cases; principally, that this proposal would require significant revision of the billing systems. NS-PGL Ex. JM-1.0 at 12-14. In surrebuttal, Mr. McKendry continues to reject this proposal based on the responsibilities that the Company would have to review the appeal of each marketer.

In rebuttal testimony, Staff witness Sackett supported CNE's super-pooling proposal. Mr. Sackett noted that "CNE specifically altered its proposal from that made in the last [Peoples Gas rate] case to be consistent with the Commission's decision in Nicor Gas' last rate case. Order, Docket 08-0363, March 25, 2009, at 126." Staff Ex. 26.0R at 47. The Commission rejected CNE's super-pooling proposal in Peoples Gas' last rate case due to concerns with billing system complexity and excessive utility involvement with suppliers and their customers.

In light of the fundamental differences between the proposals that CNE made in the last rate case and the instant case, which is identical to the process approved by the Commission in Nicor Gas' last case, Staff maintains that the Commission should approve CNE's recommendation here. Staff believes that the burden of the review is not onerous given the fact that this review process would occur after the bill is received, which is after the Critical Day is past \CNE Ex. 1.0 at 25-26 and CNE Ex. 2.1 and that, in this respect, it would be similar to any other billing discrepancy which a supplier could raise. Additionally, Staff asserts that this should make it unnecessary to modify the billing system. Furthermore, the Nicor Gas method allows the utility to work on the billing discrepancy directly with suppliers, who pay the Critical Day penalties (through the Imbalance Account Charge) under Rider P (ILL. C. C. NO. 28, Second Revised Sheet No. 95 and ILL. C. C. NO. 17, Second Revised Sheet No. 89 Peoples Gas Ex. VG-1.1, p. 70; North Shore Ex. VG-1.1, at 60) instead of with customers and therefore would not entangle the Companies in the supplier/customer relationship.

Staff asserts that its review of the evidence shows that the Companies have not provided evidence that they are unable to implement CNE's proposal, nor have they shown how they differ from Nicor Gas.

d) Compromise Methodology

In their Brief on Exceptions, the Utilities state that they discussed super pooling with CNE-Gas and proposed a method under which suppliers would be able to take steps to reduce or avoid penalty charges on Critical Days. This method differs somewhat from CNE-Gas' proposal, but it accomplishes the same objective. The proposal applies to Critical Days, which means that it applies to Rider SST customers and suppliers serving Rider SST customers under Rider P, as Critical Days have no adverse effect on Rider FST. When the Utilities declare a Critical Day, suppliers would have the opportunity to notify the Utilities, in writing by the first business day of the month following the Critical Day,that they intend to participate in a Critical Day Reallocation. "Reallocation" means that a supplier may, after-the-fact, move gas that it delivered to one or more of its Rider SST pools on a Critical Day to another one or more of its Rider SST pools. For example, assume a supplier has three Rider SST pools and delivered 100 units to each pool on a Critical Supply Shortage Day. One pool incurs unauthorized use charges that delivery of an additional 25 units would have avoided while the other two pools incurred no such charges and, in fact, had sufficient deliveries on that day that each could transfer (reallocate) deliveries to the first pool and still incur no unauthorized use charges. The supplier may make reallocationsthat, in this example, eliminates the unauthorized use charges for the first pool.

The reallocation will occur after the Utilities reconcile consumption for the month in which a Critical Day(s) occurred. Suppliers would determine what reallocation of deliveries, if any, they will request for a given Critical Day(s). The supplier must submit, in writing, its reallocation. The Utilities would execute the reallocations prior to billing the month in which the Critical Day(s) occurred. This method gives suppliers the tools to avoid Critical Day unauthorized use charges through delivery reallocations that the suppliers choose. As such, it meets the goals of "super pooling."

e) Commission Analysis and Conclusion

CNE-Gas proposed that the Utilities permit Super Pooling on Critical Days, which allows all third party groups, or pools, that are under common management to be balanced in aggregate for the application of Unauthorized Usage Charges. A Critical Day is either a "Supply Surplus Day" or a "Supply Shortage Day." We agree with CNE-Gas that this is a reasonable proposal. A supplier should be able to have its penalties changed when it can show that its other commonly-managed Rider P Pools' Critical Day deliveries would have eliminated the Unauthorized Use condition in whole or in part.

The Commission agrees with CNE-Gas that because the Utilities suffer no harm on critical days when a supplier's usage overall complies with Utilities' rules, then no penalties should be assessed. In their briefs on exceptions, both CNE-Gas and the Utilities state that they have agreed upon an acceptable methodology for Implementing Super Pooling on Critical Days. The Commission finds the proposed compromise methodology to be reasonable and it is adopted.

D. Small Volume Transportation Program

1. Allocation of and Access to Company-owned Assets

a) Utilities

The Choices for You ("CFY") or small volume program refers to the customer choice program under which S.C. Nos. 1 and 2 customers may select a third party gas supplier. Rider CFY describes the terms and conditions of service for these customers. Rider AGG (Aggregation Service) describes the terms and conditions under which suppliers are able to aggregate CFY customers. Rider SBO (Single Billing Option Service) describes the terms and conditions under which a supplier may choose to issue a single bill that includes utility charges. NS-PGL Ex. JM-1.0 at 14. The Utilities implemented changes following their last rate cases and proposed no substantive changes here. *Id*. at 15. The Utilities proposed updating certain charges based on new cost studies. (NS Exs. VG-1.0 Rev. at 26 and VG-1.11; PGL Exs. VG-1.0 Rev. at 28 and VG-1.11.)

According to the Utilities, CFY customers and suppliers receive benefits from the Utilities' storage comparable to sales customers. The Utilities note that RGS witness Crist claimed that the Utilities recover the same amount of storage costs from sales and CFY customers, but CFY customers do not receive the same rights to that storage. RGS Ex. 1.0 at 10. The Utilities do not agree.

The Utilities assert that the Commission addressed this same recommendation in the Utilities' last rate cases and rejected RGS' arguments. *Peoples 2007*at 288-293. In the short period since the last rate case, sales customers have not acquired any additional or superior rights. The Utilities argue that RGS has presented no evidence that warrants the Commission reaching a different conclusion.

According to the Utilities, CFY suppliers have significant flexibility to use the benefits that storage can offer, and the Utilities' decisions for their sales customers must work around the constraints caused by the CFY suppliers. For example, CFY suppliers know by 8:45 a.m. every business day, prior to making purchase decisions, the quantity of gas they will need to deliver to the Utilities. This quantity includes an allocation of the storage injection, withdrawal and capacity rights that mirror those the Utilities use for sales customers. With this knowledge, CFY suppliers can then vary their deliveries within a 10% band, even on Critical Days, around the known delivery level for any reason, including to take advantage of market price variations. In contrast, the Utilities make daily purchase decisions for sales customers without knowing how CFY deliveries will vary from the projected quantity and must remain prepared to meet CFY variations that are not known until after the fact. (NS-PGL Ex. RD-1.0 Rev. at 27-28.) As another example, the Utilities assert that their storage injection and withdrawal rights are constrained by limitations in the pipeline providers' tariffs or other restrictions that the pipeline imposes (such as in response to *force majeure*). These limitations include injection and withdrawal ratchets and upstream source and transportation requirements. The tariffs limit where the Utilities can buy gas and how the Utilities can transport gas. Peoples Gas' storage field (Manlove Field) also has operating limitations. Conversely, the Utilities contend, the CFY suppliers deliver gas based on projected customer requirements, without regard to storage and pipeline issues, and within a 10% tolerance band. *Id*. at 28.

Moreover, the Utilities counter the RGS claim that CFY customers pay the same amount for assets as sales customers. The Utilities explain that Sales customers pay a Gas Charge that includes the Non-Commodity Gas Charge ("NCGC"). NS Ex. VG-1.1 at 17; PGL Ex. VG-1.1 at 20. CFY customers do not pay a Gas Charge but do pay an Aggregation Balancing Gas Charge. The NCGC and the ABGC each recovers non-commodity gas costs, which includes assets like purchased storage. The ABGC is less than the NCGC. Specifically, the ABGC is defined as "a non-commodity related, per therm, gas cost recovery mechanism applied to all therms delivered or estimated to be delivered by the Company to customers served under Rider CFY. This charge is equivalent to the NCGC less any costs not associated with balancing or storage. Revenues arising through the application of this charge will be credited to the Factor NCGC." NS Ex. VG-1.1 at 17; PGL Ex. VG-1.1 at 20.

The Utilities also state that they use system assets to support several benefits for CFY suppliers that would not exist if the CFY suppliers were dealing with unbundled pipeline services, as the Utilities must do. These benefits include: CFY suppliers may transport gas to the citygate using any pipeline that interconnects with the Utilities; CFY suppliers have access to storage without having to specifically nominate injections or withdrawals; and CFY suppliers receive a daily balancing service. NS-PGL Ex. RD-2.0 at 13-14.

Finally, according to the Utilities, RGS has not shown how Nicor's allocation of storage rights and management of its version of the CFY program (Customer Select) are relevant to what the Utilities can or should adopt for their programs. Nicor's system is not the same as the Utilities' systems. Indeed, it is not apparent that RGS even recognizes that North Shore does not own a storage field. The record includes no evidence as to how Nicor's supply personnel manage and support service for Customer Select. The record includes no evidence as to how Nicor coordinates service under Customer Select with its other transportation programs. (NS-PGL Ex. RD-1.0 Rev. at 26-27.) The Utilities argue that there is no record support for taking a piece of another utility's transportation program and imposing it on the Utilities.

Staff states that the storage flexibility that CFY suppliers receive is as though injections are directly into Manlove Field. That statement is incorrect. For example, the "injection period" under Rider AGG is April 1 through October 31, and the withdrawal period is November 1 through March 31. However, the withdrawal period for Manlove

Field typically runs from the first or second week of December through the first or second week of March. PGL Ex. TLP-1.0 at 5.

Also, the idea of changing CFY to provide for capacity release or direct assignment of upstream assets was not developed at all in the record. The Utilities note that, if this is RGS' true preference, it would include only pipeline assets subject to the Federal Energy Regulatory Commission's ("FERC") jurisdiction. "Capacity release" is an element of the FERC's rules (18 C.F.R. §284.8) and would not encompass company-owned assets (Peoples Gas' Manlove Field and needle peaking assets) that, otherwise, seem to be part of RGS' proposal. NS-PGL Ex. RD-2.0 at 15.

In response to Staff's suggests of a workshop process as an alternative. There is no evidence that CFY customers are not receiving the service for which they are paying. The record supporting a change to CFY was woefully underdeveloped. There is no basis for the Commission to order workshops.

Finally, RGS seeks to make much out of what it called a workpaper that it claimed the Utilities withheld. RGS Init. Br. at 17-23. This is a red herring. The Utilities explained why the document was not a workpaper and, therefore, not produced as such. Tr. at 368-372.

The Utilities maintain CFY customers receive access to assets that are comparable to, if not superior to, what sales customers receive and, therefore, the various proposals to change the program should be rejected.

b) RGS

The basic position of RGS is that because the Companies' charges to CFY customers for assets are essentially the same as the charges the Companies assign to their own customers, CFY customers should receive a similar allocation of, and have similar access to, those assets. The simplest way to assure this is to allow the upstream and on-system assets to follow the customer through capacity release programs. Alternatively, additional flexibility can be provided to the CFY supplier with respect to the deliveries, similar to what occurs in the Nicor program, to provide CFY customers something comparable to asset release and assignment. Through either option, a customer would have more equitable access to assets for which they pay. Although asset assignment on a recallable basis would be a more direct way of achieving equity, for purposes of this proceeding, RGS focuses on revisions to the Companies' program that are more consistent with the Nicor program, since it was recently approved in the Nicor rate case proceeding and appears to be working well.

The Companies use a combination of on-system and up-stream assets to meet the design or peak day needs of its system. These assets include on-system storage (Manlove Field), storage purchased from pipelines, and firm transportation purchased from pipelines. The way in which the Companies allocate their assets, RGS argues, disadvantages customers who choose to purchase the commodity of natural gas from CFY suppliers rather than from the utility. When a customer elects to purchase its commodity from a CFY supplier, the Companies do not reduce the upstream and on-system assets it holds; rather, they continue to hold those assets and continue to charge the CFY customers for those assets. However, in this process, the Companies do not release the assets to the CFY customer or the CFY customer's supplier, and do not provide the customer with usage rights that are at all equivalent to the charges that the CFY customer continues to incur for these upstream and on-system assets.

According to RGS, this is one of the primary ways in which the Companies have created an uneven playing field between CFY suppliers and the Utilities when they compete for small commercial and residential customers. As a result of the Companies' program, CFY participation has stagnated at a three percent (3%) level – demonstrating that changes to the program are necessary. The Commission Staff agrees with RGS that it is not too soon to revisit the CFY program. Accordingly, RGS proposes that in order to provide non-discriminatory service, the Companies should:

> a. Allow CFY Suppliers to have daily injection and withdrawal rights that are commensurate with the rights and flexibility provided by the assets allocated to CFY customers through various charges.
>
> b. Allow CFY Suppliers to have monthly targets for injections and withdrawals that are commensurate with the Companies' operations.
>
> c. Allow CFY Suppliers to manage daily deliveries to a target provided by the Companies with +/- daily tolerance and impose appropriate penalties for CFY Suppliers not hitting delivery target range. The daily target should be the Company's best estimate of the customer usage for that particular supplier on that given day.
>
> d. Reduce punitive month end tolerance penalties that are not cost-based.

RGS Ex. 1.0 at 7-8.

a. Equal access to upstream and storage assets is critical to fostering a competitive market that benefits customers

The proper allocation of assets is central to the ability of CFY customers to receive the benefits of the assets for which the CFY customers are paying. With respect to the upstream assets, if CFY customers are not provided access, then their supplier has to go out onto the market and contract for replacement assets to be able to serve the customers throughout the season, and on a peak day. This creates redundant assets on the system, and for the CFY customer requires them to pay for assets significantly in excess of 100% of a peak day.

Mr. Crist testified that the benefits associated with the use of natural gas storage facilities can be separated into three general categories. RGS Ex. 1.0 at 9. First, storage provides a seasonal hedge by allowing suppliers to inject gas into storage during the injection season (roughly April through October), when spot prices are typically low, and withdraw gas from storage during the withdrawal season (roughly November through March), when spot prices are typically high. Second, storage facilities allow suppliers to hedge daily price volatility in natural gas markets and meet day-to-day fluctuations in demand. Third, storage can reduce the need for more expensive pipeline capacity during periods of peak demand. Mr. Dobson, the

Companies' principal witness on customer assets issues, agreed with Mr. Crist's characterization of these benefits. Tr. at 345-346.

Mr. Crist explained that there are two types of storage assets relied upon by the Companies, the costs of which are recovered from all customers: on-system storage facilities and off-system leased storage services. RGS Ex. 1.0 at 9-10. On-system storage (at Manlove Field) is owned by the Companies and directly connected to the Companies' distribution system. The costs of on-system storage are recovered equally from all residential and commercial customers through base rate delivery charges. Off-system storage is connected to the interstate pipelines that serve the Companies' distribution system. Off-system storage is leased by the Companies through contracts with third-parties. The Companies may also have contracts with interstate pipelines for firm transportation. The costs of off-system storage and firm transportation are recovered from residential and commercial customers whether they are on sales service, via the Non-Commodity Gas Charge ("NCG Charge"), or on CFY, via the Aggregation Balancing Gas Charge ("ABG Charge"). Both of these charges provide for the pass-through of interstate pipeline transportation costs as well as leased storage costs. *Id*. In other words, through a combination of base delivery charges and the ABG Charge, the Companies charge CFY customers the *same amount* for assets (on-system storage, upstream storage and upstream firm capacity) as they charge their own sales customers. There are also upstream capacity assets that help to round out the Companies' asset supply picture as it relates to a peak day, which also need to be considered in solving the inequity picture.

In order to solve the inequity that RGS sees, it proposes to either put in place a more robust use of storage needs (which is their primary focus) or to significantly adjust downward the CFY ABG Charge to take into consideration the absence of access to those assets.

b. The Companies improperly limit CFY customers' allocation of and access to the assets that CFY customers pay for

If CFY customers pay the same amount for assets as sales customers, CFY customers should receive the same allocation of, and access to, those assets as the sales customers. The evidence shows, RGS argues, that access to the storage is more limited for CFY customers, and the rights to storage are not allocated equally. CFY customers have a lesser allocation of the daily and monthly injection and withdrawal rights compared to the sales customers. As a result of the misallocation, PGLC uses Company-owned assets to satisfy 93% of its sales customers' peak day demand, while CFY suppliers only can satisfy 71% of their customers' peak day demands with Company-owned assets.

The most important impediment to CFY customers taking advantage of on-system and upstream storage and upstream firm transportation are the Companies' injection and withdrawal restrictions. Compared to the flexibility given to the Utilities, CFY Suppliers have limited options in varying the amount of gas withdrawn from and injected into storage. Under the Companies' rules, the amount of storage capacity withdrawn from and injected into storage on a daily and monthly basis by each CFY supplier is a fixed number that is administratively determined by the Companies with a limited consideration of actual weather. RGS Ex. 1.0 at 11-12. Under those rules, monthly storage capacity levels vary by month and storage withdrawals vary somewhat with heating degree days based on the output of an administratively determined algorithm. With little injection or withdrawal flexibility, CFY suppliers have limited ability to hedge daily price volatility, provide seasonal hedging, and meet day-to-day fluctuations in demand – that is, they have limited ability to take advantage of the benefits that even Mr. Dobson agreed are conferred by access to storage assets. Instead, the CFY suppliers must supplement the need for additional pipeline capacity during periods of peak demand. This lack of flexibility and need for additional pipeline capacity artificially inflates the cost of gas provided by CFY suppliers and creates an uneven playing field for CFY suppliers seeking to compete with the Companies' regulated sales service. *Id.* at 11-15.

This Commission already has acknowledged that excessive restrictions on injection and withdrawal of storage for the CFY program should be removed. In ICC Docket 01-0470, the Commission rejected the Companies' proposal to impose excessive storage withdrawal requirements on the predecessor to CFY, Rider SVT, stating:

> The Commission finds the Company's proposal problematic because it requires that suppliers withdraw or inject the same amount of gas on each day of a given month and, therefore, deprives SVT Suppliers of the ability to hedge daily price volatility, meet day-to-day demand fluctuations and supplement needs for additional pipeline capacity during peak demand periods through storage use.

Docket 01-0740 March 5, 2002 Order at 100-101, quoted at RGS Ex. 1.0 at 14:305-12. The Commission then directed the parties to conduct workshops in order to provide CFY suppliers with greater flexibility over the use of allocated storage capacity. At the conclusion of the workshops, Peoples filed the tariffs that are the basis for the existing CFY program. After several years of operating under these rules, however, it has become clear that CFY customers are being deprived of the access to storage and flexibility that they should be provided.

Mr. Crist provided an example of how excessive restrictions create an imbalanced playing field between CFY suppliers and the Companies. RGS. Ex. 1.0 at 15:338-16:355. When low price gas is available in the spot market, CFY Suppliers may be unable to purchase that gas to meet its customers' daily needs because the storage injection and withdrawal schedule imposed by the Companies may require that storage assets be withdrawn on that day. The Companies, however, can react to such market changes and, within the confines of the geological withdrawal limitations of their storage assets, modify their withdrawals for their own customers to allow themselves to purchase inexpensive spot market gas. *See Id*. As noted above, Mr. Dobson agreed that utilities use their storage portfolios to obtain such daily benefits of storage, as well as seasonal and peak day benefits from storage. Tr. at 347.

Mr. Crist testified that most utilities that host successful Choice programs allow access to storage and flexibility similar to that being proposed by RGS. These would include, in addition to Nicor in Illinois, East Ohio Gas and Columbia of Ohio, Atlanta Gas

Light (which has all of its residential customers participating in Choice), Dominion Peoples, Niagara Mohawk, and National Fuel. RGS Ex. 1.0 at 17:379-87.

c. The Companies failed to even evaluate the RGS proposal to have the CFY program mirror Nicor's customer choice program

In order to ensure a set of rules and regulations for access to storage gas that are workable and fair to both the utilities' sales customers and to CFY customers, Mr. Crist proposed that the Companies adopt the plan being used by Nicor Gas. Those rules were negotiated by the parties in Nicor's last rate case, ICC Docket No. 08-0363, endorsed by Staff, and approved by the Commission in its final order in that docket. Mr. Crist attached a copy of Nicor Rider 16, which sets out the conditions for Nicor's "Customer Select" program, which is its version of the Companies' CFY program. The key elements of those rules are as follows:

1. seasonal storage capacity that reflects the cost allocation of both on-system and off-system storage assets;
2. daily withdrawal and injection capability that reflects the combined flexibility of both on-system and off-system storage assets;
3. daily delivery flexibility expressed by the current +/- 10%;
4. monthly storage withdrawal and injection targets that must be met under threat of penalty; and
5. a month-end tolerance of +/- 5% that is enforced by a reasonable penalty.

RGS Ex. 1.0 at 18.

Instead of addressing RGS' recommendation that the CFY program adopt the storage usage elements of the Nicor program, Companies witness Dobson argued that the Companies are different from Nicor because Nicor has several storage fields and Peoples Gas only has one and North Shore none. NS-PGL Ex. RD 1.0 at 27. He never explained, however, the relevance of the number of storage fields owned by a gas utility to the allocation of storage among sales and CFY customers nor did he present any data on the size of the storage field capacity which would be necessary to support the point he failed to make.

The Companies' cavalier attitude was also evident in their response to Mr. Crist's calculations of the amount of assets available to CFY customers and sales customers. In his rebuttal testimony, Mr. Crist testified the Companies control delivery assets designed to provide 103% of a peak day in deliverability for their sales customers yet only provide enough assets to CFY customers to provide 71% of their peak day needs. This disparity exists even though both groups of customers are paying the same amount to the Companies for the use of those assets. *See*, RGS Ex. 2.0 Rev at 7-8. The source of the calculations was provided as an exhibit to Mr. Crist's testimony, RGS Ex. 2.1. A graphical representation of the calculations was provided as (RGS Ex. 2.2 Rev.) The workpaper supporting those calculations was provided to the Companies the day after the filing of that rebuttal testimony, as provided for in the case scheduling order.

The Companies apparently decided that rather than examine this significant comparison of assets provided to sales and CFY customers, they would simply provide broad criticism with no analysis. First, the Companies conducted no discovery of Mr. Crist's calculations. *See*, Tr. at 362. Next, Mr. Dobson decided that it was not even worth his time to look at Mr. Crist's workpaper that had been provided to the Companies. *See* Tr. at 353. Then, after his complete lack of examination of Mr. Crist's analysis, Mr. Dobson simply claimed in his Surrebuttal Testimony: "Mr. Crist provides no analysis to support his claim and includes only a graphic representation of what assets he believes are available to sales customers and to CFY customers." NS-PGL Ex. RD 2.0 at 15.

Even more disturbingly, during the hearing, it was revealed that Mr. Dobson had created a workpaper supporting his Surrebuttal Testimony that had not been provided to the parties, as required by the case management order in this proceeding. Tr. at 363-365. In his Surrebuttal Testimony, Mr. Dobson criticized Mr. Crist's comparison of assets available to sales and CFY customers by arguing that the amount of gas available to sales customers should be adjusted down by removing needle peaking assets and commodity purchases made at the city-gate. NS-PGL Ex. RD 2.0 at 15. His testimony provided no figures showing how that would affect the 103% of peak that Mr. Crist had testified was available to sales customers. During the hearing, referring to a workpaper he had not provided to RGS, he suddenly was able to precisely calculate the effect of his adjustment – it would reduce the gas available to sales customers from 103% of peak to 77 % of peak.

d. Even with the Companies' modification, it is clear that storage assets are not made equally available

Using the previously undisclosed Dobson workpaper, Mr. Crist was able to calculate that the effect of removing city gate purchases from the gas available to sales customers reduces their supply to approximately 93% of peak. *See* Tr. at 556. Nothing in the Dobson analysis affected the amount of gas assets available to CFY customers – 71% of peak. *Id.* Thus, while the discrepancy is not as large as Mr. Crist had calculated in his Rebuttal Testimony – as depicted on RGS Ex. 2.2REV – the point he made stands unrebutted – CFY customers, who pay the same amount as sales customers for on-system storage and upstream assets, receive far less that sales customers – sales customers are provided enough assets to meet 93% of peak while CFY customers are only provided enough to meet 71% of peak. *Id.*

This demonstrates that *even with* the modification advocated by Mr. Dobson, CFY suppliers face a considerable disadvantage because in order to overcome the deficiency in the allocation of assets, CFY suppliers must contract for, and pay for, additional deliverability assets. That is a cost burden that Peoples Gas has created, to the detriment of CFY suppliers. *See*, Tr. at 556.

e. Conclusion: The Commission should order the Companies to revise their CFY programs to provide a fair allocation of and access to the Company-owned storage assets for which CFY customers pay

RGS has demonstrated that CFY customers are not receiving the access to and control of on system and upstream assets that is available to sales customers. Given that the Companies' rates are set so that CFY customers pay the same as sales customers for those assets, their rights should be the same. The Commission should therefore adopt the proposal of RGS and direct the Companies to revise their program to incorporate the key elements of the Nicor Customer Select program identified by Mr. Crist. Such rules would level the playing field and would also provide some benefit to the Companies by shifting the risk and responsibility of managing asset deliveries and storage operations to CFY Suppliers.

At the very least, the Companies should be directed to increase the asset allocation so that CFY customers receive the same assets as sales customers. As noted above, sales customers currently have access to assets that equal 93% of peak needs, whereas CFY customers only have access to assets that equal 71% of peak needs. The Companies should increase the allocation to CFY customers so that it is equal to the allocation to sales customers.

The least favored solution recommended by RGS is that the Companies reduce the amount paid by CFY customers for assets to reflect the fact that they have less rights and access to assets than sales customers.

The Companies dispute the fact that CFY suppliers have less flexibility to use on-system and upstream assets than the Companies' sales customers. They then list certain elements of their storage injection and withdrawal rules and claim these restrictive regulations are in reality, beneficial to CFY suppliers. For example, the Companies' Brief claims that CFY suppliers should be thankful that at 8:45 a.m. the Companies will inform them that they must deliver a specific amount of gas the next day, because the Companies let them deliver within a 10% range of that specific amount. The Companies are essentially arguing that, "while we have put handcuffs on you, you should be happy that they are a bit loose." More specifically, this 10% band fails to compensate for the fact that the specified amount is an arbitrary and unnecessarily restrictive figure. That delivery figure takes limited consideration of actual weather. *See*, RGS Ex. 1.0 at 11-12. Thus, regardless of the weather and regardless of market prices for gas, CFY suppliers must deliver within 10% of the amount set by the Companies. Further, this assertion completely ignores the fact that although CFY customers pay for enough assets to meet 93% of a peak day through base rate and ABG Charges, they nonetheless only have access to 71% of those assets. Further, the "flexibility" Companies provide is taken into consideration when arriving at the 71% access level which further dilutes the Companies' argument.

Moreover, the storage levels are also administratively determined using an algorithm for each month with only some consideration of heating degree days. It is this combination of limited injection and withdrawal capability that restricts CFY suppliers from hedging daily price volatility, providing seasonal hedging, and meeting day-to-day fluctuations in demand. In summary, giving suppliers a 10% daily delivery allowance hardly compensates for the severe restrictions in delivery suppliers and creates an uneven playing field for CFY suppliers seeking to compete with the Companies' regulated sales service. *SeeId.* at 11-15.

The Companies also claim that their own storage injection and withdrawal rights are constrained by limitations in the pipeline providers' tariffs or other restrictions that the pipeline imposes, such as in response to *force majeure* and by operating limitations on Manlove Field. They claim that CFY suppliers have no comparable storage and pipeline issues. That statement is simply wrong. The CFY suppliers' gas deliveries do not magically appear at the city gate. The CFY suppliers must have gas delivered over the same pipelines as the Companies and therefore face the pipeline restrictions for their deliveries as the Companies face for theirs.

The Companies also argue that CFY suppliers obtain several benefits from the Companies' system assets, such as the ability to transport gas to the city gate using any pipeline that interconnects with the Utilities, access to storage and daily balancing. This argument completely misses the point. RGS is not arguing that it does not receive any benefit from system assets. The problem is that CFY customers pay the same amount as sales customers for those system assets through base rates and ABG Charge, but receive less benefit from those asses than sales customers. The chart contained on page 21 of RGS's Initial Brief, which is the version of RGS Ex. 2.2 Rev that contains the adjustments to that exhibit agreed to by Mr. Crist during the hearings, illustrates this difference. As can be seen from that chart, sales customers are provided assets that equal 93% of their peak, whereas CFY customers are provided assets that only equal 71% of their peak. That difference must be made up by the CFY suppliers, who must contract for, and pay for, additional deliverability assets since CFY customers are required to meet their delivery obligations. Keep in mind that the 71% access takes into consideration the 10% tolerance. *See*, RGS Ex. 2.0 at 9. So, RGS agrees that CFY suppliers and their customers use the Companies' assets, but they do not get what they pay for.

RGS agrees with the three point recommendation of Staff. RGS is concerned, however, with the alternative recommendation that the parties begin a workshop process to review and modify the CFY program. The Companies have demonstrated a complete disregard of RGS's recommendations -- bordering on contempt. It seems that an open ended process without clear direction from the Commission will have little chance of success if it depends upon good faith negotiating by the Companies. RGS therefore recommends that if the Commission decides to accept the Staff's alternative proposal for workshops, then the Commission should state that the final CFY rules and procedures should vary from the Nicor rules and procedures only where good cause can be shown.

c) Staff

RGS witness Crist proposed that the Commission order the Companies to provide CFY suppliers with more flexibility with storage. Mr. Crist points out that the injection and withdrawal rights under CFY reflect the rigidity of on-system storage with regimented injections and withdrawals. "Under the Companies' rules, Alternative Suppliers are prevented from varying the amount of gas withdrawn from and injected into storage on a month-to-month basis even though such flexibility could be provided using the storage assets that Choice For You customers pay for. Instead, the amount of storage capacity withdrawn from and injected into storage on a daily and monthly basis is a fixed number that is administratively determined by the Companies with a limited consideration of actual weather." RGS Ex. 1.0 at 11-12.

So, CFY suppliers are treated as though the injections that they are making are going directly into Manlove field. The more flexible *storage* assets in the Companies' portfolios are the off-system storage assets. NS-PGL Ex. RD-2.0 at 7, which the CFY customers do pay for equally. "Despite the fact that the Companies recover the same amount of storage costs from both sales and CFY customers, CFY customers have a lesser allocation of the daily and monthly injection and withdrawal rights compared to the sales customers." RGS Ex. 1.0 at 10. Even though the ABGC excludes Firm Transportation contracts, the CFY supplier flexibility does not reflect the flexibility of the off-system portion of those storage assets for which these customers and suppliers do pay for equally with sales customers. *Id*.

Mr. Crist points to an example of this disparity.

> Not having the same level of storage rights that the Companies have (on a per-customer basis) deprives Alternative Suppliers of the ability to fully hedge daily price volatility and meet day-to-day fluctuations in demand, and they must supplement the need for additional pipeline capacity during periods of peak demand….Alternative Suppliers have no flexibility associated with the rights that the allocated storage assets should provide.

RGS Ex. 1.0 at 12.

Companies witness Dobson rejected the RGS proposal because CFY customers know in advance a volume that they are required to deliver, they can deviate from that quantity by 10%, and they are shielded from the realities of constraints of on and off-system storage by the Companies. NS-PGL Ex. RD-1.0 Rev. at 27-28. However, Mr. Dobson admitted that he had not read RGS Ex. 1.1 which is the Nicor Gas tariff for Customer Select suppliers. Tr. at 388. Mr. Dobson was apparently not concerned with learning the details of RGS' proposal to modify CFY to be similar to this other program. Consequently, his testimony should be considered in this light.

Staff believes that the Companies' current program raises longstanding concerns previously identified and addressed by the Commission in Docket 01-0470:

> The Commission finds the Company's proposal problematic because it requires that suppliers withdraw or inject the same amount of gas on each day of a given month and, therefore, deprives [alternative gas suppliers] of the ability to hedge daily price volatility, meet day-to-day demand fluctuations and supplement needs for additional pipeline capacity during peak demand periods through storage use.

The Peoples Gas, Light and Coke Company, Docket 01-0740, at 39 Order, March 5, 2002.

Comparing Rider AGG (the CFY Supplier tariff) with Nicor Gas Rider 16 (RGS 1.1) reveals significant differences between the two programs in daily delivery targets, daily storage activity and monthly storage activity. Comparing the daily delivery targets shows that the Companies use (customer's estimated daily usage + the *required* storage activity) ±10% Rider AGG, Aggregation Service, Applicable to Rider CFY, Section E - Delivery Determination, Peoples Gas Ex. VG-1.1, at 82; North Shore Ex. VG-1.1, at 66. while Nicor Gas uses the customer's estimated daily usage ±10% + the *allowed* storage activity. Under Nicor Gas' Customer Select, *daily* storage activity is a right or option; under CFY it is an obligation. Rider AGG, Aggregation Service, Applicable to Rider CFY, Section E - Delivery Determination, Peoples Gas Ex. VG-1.1 at 82; North Shore Ex. VG-1.1 at 66. Additionally, the monthly storage inventory targets for the Companies are fixed numbers. RGS Ex. 1.0 at 11-12. On the other hand, Nicor Gas only requires the bank to be filled to 95% and only be emptied down to 35%. Also, it provides for monthly inventory *ranges* that provide for flexibility in how the suppliers use their storage. RGS Ex. 1.1 at 4.

While Staff supports RGS' position that there should be revised injection and withdrawal rights that better reflect the flexibility of all storage assets, RGS is incorrect that CFY customers pay equally for Firm Transportation ("FT") assets. In fact, CFY customers do not pay at all for FT. Staff witness Sackett is clear in his Revised Direct Testimony, that FT costs are excluded from the Aggregation Balancing Gas Charge.

Staff notes that in RGS's comparison of the relative delivery from the system for sales and CFY customers, RGS removed the citygate deliveries from RGS Ex. 2.2REV because CFY customers do not pay for those deliveries. However, RGS' comparative analysis fails to remove the additional 12% that reflects the FT that CFY customers also do not pay for.

Staff agrees that off-system *storage* costs are included in both the NCGC and the ABGC and, as such, are recovered equally from sales and CFY customers. Staff continues to believe that there is merit in a comparison of these assets, excluding the FT, which RGS incorrectly includes in its analysis. Rider AGG reflects only the flexibility of on-system storage assets, while CFY customers pay for both on and off-system storage assets equally with sales customers. Furthermore, even if one removes the 12% FT from RGS' analysis, this comparison still shows a 82% to 71% advantage for sales customers in deliverability from those assets which are commonly paid for.

Staff believes that Mr. Crist provided a compelling case for changing the CFY program to reflect the increased injection and withdrawal flexibility of off-system storage assets for which CFY customers pay. It is clear from comparing Rider AGG, Aggregation Service to Nicor Gas' Rider 16 – Supplier Aggregation Service RGS Ex. 1.1 that Customer Select provides significantly more injection and withdrawal flexibility than Choices For You. Therefore, Staff recommends that the Commission order the Companies to implement the following which are based on the Nicor program:

1. Daily injection and withdrawal rights based on the methods provided in RGS Ex. 1.1 – Daily Storage Withdrawal Capacity and Daily Storage Injection Capacity.

2. Monthly targets for injections and withdrawals based on the method provided in RGS Ex. 1.1 – Storage Inventory Target Levels.

3. Daily delivery targets provided by the Companies based on the best estimate of the customer's daily usage with a daily tolerance of ±10% like RGS Ex. 1.1 – Daily Delivery Range.

In the alternative, Staff recommends that the Commission order a workshop process with the Companies, Staff and Suppliers to review the CFY Program, compare it to Nicor Gas' Customer Select program, and develop new injection and withdrawal rights that better reflect the flexibility of all storage assets.

d) Commission Analysis and Conclusion

RGS provided compelling evidence to show that the CFY program is not functioning as well as it could. This evidence showed CFY participation at only 3%. Staff acknowledges the need and supports changes in the Utilities' CFY program. While it is clear that changes to the CFY program are needed, nothing more of clarity appears on the record. RGS recommends a wholesale adoption of the program recently approved by the Commission for Nicor. Whether this would be appropriate for the Utilities' choice program is not known because the Utilities chose not to seriously respond to RGS' proposal. Accordingly, we are left with an incomplete record.

Having found that the Utilities should adopt the recommendations of RGS and Staff, the Commission believes that it is necessary for the parties to work together to formulate language that tailors the Nicor choice program provisions for access to and allocation of company assets to the Utilities' operations. Thus, Staff's proposal to hold workshops is the only reasonable option of record to address the CFY program.

The Commission directs the Utilities to come to the workshops prepared to discuss the Nicor program, as presented by Mr. Crist. The Utilities should be prepared to explain which parts are appropriate for their program, which are not, and why they are not. For those parts of the Nicor program that the Utilities believe are not appropriate for their program, they will come prepared to present alternatives to address the issues raised by RGS.

The workshops will cover all the small volume transportation program issues. The workshops participants shall be technical and other in-house working personnel from the affected companies and the Commission Staff.

In its brief on exceptions, Staff proposes that the Commission adopt the Nicor program completely and merely discuss how the Nicor program will be implemented at the workshop. This would defeat the purpose of the workshops. As stated above, there is not sufficient evidentiary support adoption of the Nicor program at this time. The Nicor program does, however, provide a good starting point for discussions at the workshops.

The Commission wishes to make it clear that it has already ruled that the CFY program must include the key aspects of the Nicor program identified by the Commission Staff (Staff Brief at 197):

1. daily injection and withdrawal rights based on the methods provided in RGS Ex. 1.1 – Daily Storage Withdrawal Capacity and Daily Storage Injection Capacity.

2. monthly targets for injections and withdrawals based on the method provided in RGS Ex. 1.1 – Storage Inventory Target Levels.

3. daily delivery targets provided by the Companies based on the best estimate of the customer's daily usage with a daily tolerance of ±10% like RGS Ex. 1.1 – Daily Delivery Range.

Thus, the only Allocation of and Access to Company-owned Assets issues to be discussed at the workshops will be how to implement these changes, and not whether they should be implemented.

2. Payment for Company-owned Assets/Aggregation Balancing Gas Charge

a) Utilities

RGS proposed, as an alternative to its request for greater access to storage assets, that the Commission require the Utilities to reduce theABGC. Reducing the ABGC would only be appropriate if the CFY customers were not receiving the benefits for which they were paying through the ABGC. Moreover, RGS witness Crist's contention that the Utilities "recover the same amount of storage costs from both sales and Choices For You customers" is incorrect. RGS Ex. 1.0 at 10.

Mr. Crist states that off-system storage costs are recovered from sales customers through the Non-Commodity Gas Charge ("NCGC") and from CFY customers through the ABGC. *Id*. This is correct, but disingenuous in the context of arguing that the Utilities recover the "same amount" of storage costs from sales and CFY customers. *Id*. In fact, the ABGC is less than the NCGC. Specifically, the ABGC is defined as "a non-commodity related, per therm, gas cost recovery mechanism applied to all therms delivered or estimated to be delivered by the Company to customers served under Rider CFY. This charge is equivalent to the NCGC less any costs not associated with balancing or storage. Revenues arising through the application of this charge will be credited to the Factor NCGC." NS Ex. VG-1.1 at 17; PGL Ex. VG-1.1 at 20. This rate design recognizes that the Utilities provide storage and balancing services to the CFY customers and suppliers. Consequently, only costs associated with those services are properly recovered from the ABGC, and those are the only costs recovered from the CFY customers. Further reducing the ABGC would result in sales customers subsidizing the CFY customers by paying costs associated with the balancing and storage services that CFY customers and their suppliers receive. Those services are substantial and there is no record support for reducing the ABGC.

b) RGS

RGS asserts that CFY customers pay for on-system storage and upstream assets through a combination of base delivery rates and the ABGC. Base rates are paid equally by sales and CFY customers; but the ABGC is paid solely by CFY customers. Thus, if the Commission decides not to modify the rules and regulations for access to storage in the manner proposed above, it should direct the Companies to reduce the AGB Charge to reflect the reduced amount of assets provided to CFY customers in comparison to the assets afforded to sales customers.

Again, just to be clear, RGS would much prefer that the Commission direct the Companies to modify their storage and injection rules in a manner consistent with the rules being used by Nicor. Such rules would give CFY providers the opportunity to save their customers money with careful management of their gas supplies. If, however, the Commission allows the Companies to continue to restrict the ability of CFY providers to manage their customers' gas, then the Commission should lower the CFY charges to reflect that lack of flexibility.

The Companies also dispute whether CFY customers pay a similar amount for assets as sales customers. According to the Companies, the ABGC is not the same amount as the equivalent sales customer charge (the NCGC) because unlike the NCGC, the ABGC does not include costs not associated with balancing or storage. It is not relevant whether the sales and CFY charges are identical. The only important issue is whether the storage and balancing components of those two charges are the same, and the Companies do not deny that fact. If those components are the same, then the benefits should be the same. As shown by RGS Ex. 2.2 Rev, the benefits are not the same. Thus, if the Commission leaves the CFY rules for injections and withdrawals unchanged, then it should direct the Companies to reduce the ABG Charge. RGS agrees with the Staff, however, that this issue will be moot if it either immediately modifies the CFY program along the lines recommended by Mr. Crist or initiates workshops to craft those changes.

c) Staff

RGS witness Crist proposed that if the Commission did not provide greater access to storage, then the ABGC should be reduced to reflect the limited storage use. No one offered testimony to refute this position.

However, Staff believes that Mr. Crist did not provide sufficient basis for his recommended reduction because he did not show that his proposal to reduce the ABGC by 34% would be cost-based and that it would achieve the equity that he argued was lacking by his comparisons in RGS Ex 2.2. , Tr. at 563. If the Commission orders the workshop advocated by Staff above on the issue of Allocation of and Access to Company Owned Assets, then the RGS' primary issue is being addressed and the ABGC should be considered in that context and not changed here.

d) Commission Analysis and Conclusion

The Commission has adopted Staff's proposed workshop process. Accordingly, RGS' primary issue will be addressed in that forum. With respect to the proposed reduction to the ABGC, it is here denied.

3. Allocation of Administrative Costs and Related Charges

a) Utilities

RGS contends that the Utilities should recover through base rates applicable to all customers the costs that are the basis for the CFY administrative charges and the LDC Billing Option. The proposal is inconsistent with cost causation principles and would result in sales customers subsidizing customers who elect to take transportation service. NS-PGL Ex. VG-2.0 Rev. at 64. The CFY Administrative Charge recovers the Utilities' cost of administering their CFY transportation programs. The Utilities presented a specific cost study, identifying the activities and functions and the related costs, to support the proposed CFY Administrative Charges. NS-PGL Ex. VG-2.0 Rev. at 63; NS Ex. VG-1.0 Rev. at 26; NS Ex. VG-1.10; PGL Ex. VG-1.0 Rev. at 28; PGL Ex. VG-1.10. The LDC Billing Option charges recover the Utilities' cost of rendering a bill with supplier specified charges, on behalf of the supplier, and remitting customer payments to the supplier. (NS-PGL Ex. VG-2.0 Rev. at 63-64.)

RGS' analogy to the Utilities' call center is flawed. Call center costs are reasonably bundled in the customers' rates, just as other expenses such as operational and maintenance or administrative and general costs, that necessarily support utility service are bundled in the rates. There is no distinct group of customers that chooses to purchase a call center service to whom the Utilities would bill these costs. It would be imprudent and impractical to unbundle the call center and offer it as a distinct service.

The Utilities contend that the analogy to energy efficiency programs is similarly flawed. The Utilities' Rider EEP, Enhanced Efficiency Program, is a funding mechanism. *Peoples 2007* at 184 ("The Commission further finds that Rider EEP is a reasonable means by which the Utilities may recover the EEP costs that they incur as a result of the programs and benefit ratepayers in that they will only be charged the amount actually spent."). Customers do not purchase "Rider EEP service." Rider EEP generates funding that is then used to support programs that are offered by others. Tr. at 101; Tr. at 260-261. If Rider EEP applied only to customers, who, after the fact, participate in a program funded by Rider EEP, there would be no before the fact funding to develop and implement programs.

Finally, RGS' proposal to bundle the CFY administrative and billing option costs in charges paid by all S.C. Nos. 1 and 2 customers ignores the fact that S.C. No. 2 customers are also eligible to take the Utilities' large volume transportation services. Under RGS' proposal, an S.C. No. 2 customer who chose to take large volume transportation service would pay the administrative charges associated with both the CFY and the large volume programs. The cost-based administrative charges for the large volume transportation program are uncontested.

The costs in question are cost-based charges that are properly assessed to CFY suppliers for services those suppliers receive. Assessing these costs to all customers (sales and transportation) would be improper and should be rejected.

b) RGS

Given the fact that CFY customers are, by definition, smaller volume customers, any unjustified "per customer" charges, regardless of how small they may sound, can act as a significant artificial barrier, denying these customers the benefits of competition.

The Companies currently impose upon CFY suppliers an "administrative" charge for each CFY customer. RGS Ex. 1.0 at 19-20. This administrative charge, which is included in the Rider AGG Aggregation Charge and the LDC Billing Option charge, is billed to CFY suppliers that elect to continue having the Companies issue a bill for the delivery charges and the CFY suppliers' gas supply charges.

There are two distinct issues relating to the Companies' administrative charges. First, it is inappropriate to impose these administrative charges only upon CFY customers and their suppliers. That is, the administrative costs associated with making customer choice available and operational should be spread among all customers who are eligible for the CFY program by including those costs in the base rates of the Rate 1 and Rate 2 customers. The administrative costs associated with many other programs – including Nicor's choice program and the energy efficiency programs of both the Companies and Nicor – similarly are recovered from all eligible customers. Second, regardless of who is required to pay these charges, the Companies have not even attempted to justify the level of this charge in the instant proceeding.

a. The Administrative and LDC Billing Option costs should be recovered from all eligible customers

Administrative costs associated with bringing the benefits of competition to all small commercial and residential customers should be recovered from all small commercial and residential customers. That is, CFY administrative costs should be recovered via the Companies' base rates for those customer classes that are eligible for CFY service (Rate 1 and Rate 2). Such a recovery mechanism would be consistent with cost-causation principles, and would mirror the way in which Nicor recovers its customer choice administrative costs, and the way in which Nicor and the Companies recover the costs associated with administering their energy efficiency programs. This also would have the pro-competitive beneficial effect of removing one more cost hurdle that a customer currently faces when determining whether or not to choose supplier for the commodity of natural gas. So, again, the playing field will be leveled, allowing for accurate and fair price signals so that customers can make informed choices in a competitive market that is equitable to all suppliers.

It is entirely appropriate to spread the costs of the administration of the CFY program to all customers eligible to take service under that program. This principle is aptly demonstrated by the method that the Companies themselves use to recover the cost of their energy efficiency programs. Such costs are spread among *all customers eligible* to take advantage of those programs, regardless of whether they actually take that service. In fact, in their last rate cases, the Companies advocated strongly that the spreading of such administrative costs is entirely appropriate.

Precisely the same principle should apply to the allocation of the customer choice administrative fee. The Companies admit that all small commercial and residential customers are eligible for the CFY program and that all such eligible customers may benefit from the CFY. Tr. at 228-229. Accordingly, there is absolutely no reason to treat the administrative fees associated with the CFY program differently from the costs caused by the EEPor by call center costs – all of those programs benefit all eligible customers, so all eligible customers should pay for them.

Similarly, Nicor recovers the administrative costs related to both its EEPand its choice program from all eligible customers. RGS. Ex. 1.0 at 21. In its last rate case, Nicor Gas agreed to apply the administrative costs related to Choice programs to all eligible Choice customers, by including those costs in their base rates. With the support of Staff, the Commission entered an Order directing that Nicor's administrative costs associated with customer choice be recovered from all eligible customers. *I*d.; Tr. at 1050-1053.

While there may be certain differences between the Companies and Nicor, there is no significant difference in the matter of the administrative costs the utilities incur to operate their choice programs. There should be no difference in the recovery of those costs – they should be recovered from all customers eligible to participate in the program.

b. The Companies have failed to justify the level of their Administrative and LDC Billing Option Charges

Regardless of the question of from whom the customer choice administrative costs are recovered, the Companies have failed to justify the level of these charges. The nature of the costs being recovered by the Administrative and LDC Billing Option Charges are set out in NS/PGL Ex. VG-1.10. These costs are supposed to be the usual and customary functions involved in rendering a bill would be contract administration, billing, billing exception processing, billing adjustments, supplier support, customer inquiries, PEGASys™ billing & support, gas scheduling, supplier billing, telecommunication, general office expenses, postage, ongoing application maintenance, and minor information technology system enhancements.

However, it is unclear which, if any of the charges that the Companies include in the CFY customers' LDC Billing Options Charge are recovering costs that are truly incremental, i.e. would not exist but for the presence of the CFY program. Mr. Crist noted that the Companies should be indifferent to whether a customer is one of its sales customers or a CFY customer. RGS Ex. 1.0 at 3-4. In either event, the Companies would have to do the same billing tasks to render a monthly bill to the customer. Yet, under the current system, a customer that leaves sales service and becomes a CFY customer automatically must pay a new charge above and beyond the base rate that the customer already shares with sales customers.

A review of NS/PGL Ex. VG-1.10 supports Mr. Crist's analysis. The CFY customers appear to pay all of the same costs that the rest of the Rate 1 and Rate 2 small volume customers pay for such services as gas transportation, billing, and call center services, but are then required to pay an incremental amount of $1,317,557. CFY customers are not provided any deductions or offsets for the services related to the Companies' providing commodity services that CFY customers do not use. In fact, the

Companies' witness Ms. Grace, who presented NS/PGL Ex. VG-1.10, confirmed that the only adjustments made to base rates are for gas costs and related bad debt of CFY customers. NS-PGL Ex. VG-2.0 at 64.

RGS propounded data requests that asked for more detail for the cost components of that $1,317,557 reflected on Exhibit 1.10. The Companies' response to every one of these data requests was the same: "requested information is not maintained in and cannot be retrieved in the requested level of detail." (*See* RGS Ex. 2.3, which contains the Companies' responses to these seven data requests). Based on those inadequate data responses, Mr. Crist concluded: "It seems the Companies have no support for the Administrative charges that are assessed to the CFY program." (RGS Ex. 2.0 Rev at 11.) Nothing at the evidentiary hearing changed this situation. On the contrary, Ms. Grace candidly admitted the Companies' lack of data to support their position. Tr. at 234-239.

The response of the Companies was to duck its inadequate record keeping and simply state that "Costs supporting Rider AGG administrative charges are provided in 21 lines of detail in Peoples Gas Ex. VG-1.10, and 19 lines of detail in North Shore Ex. VG-1.10. NS-PGL Ex. VG-3.0 at 36. That response misses the point made by Mr. Crist that the Companies have made no attempt to support the figures reflected in those 20/19 lines of detail.

In response to Staff, RGS states that even though Staff's witness supported Nicor's recovery of administrative costs from all eligible customers, the Commission Staff does not support RGS' position here. RGS argues that this is contrary to the position expressed by Staff witness Sackett. Staff attempts to back away from Mr. Sackett's support of the Nicor decision to spread the administrative costs of its choice program among all customers, arguing that his support for this treatment was linked to his support for the Memorandum of Understanding in Nicor. On the contrary, Mr. Sackett considered each part of that agreement separately. Referring to the recovery of administrative costs by all eligible customers, Mr. Sackett stated in his testimony in that case: "I agree with the MOU's treatment of this issue and recommend that the Commission approve it." Tr. at 1053:10-12. Mr. Sackett also confirmed that the proposal made by Mr. Crist in this case is consistent with the position Mr. Sackett took in the Nicor case: "I think with regard to the administrative costs, yes, it is the same basic issue and his position is essentially the same as the position that I took in that case." Tr. at 1055.

Staff also disagrees with RGS' finding that the Companies have not shown that there are any incremental costs caused by the CFY program, let alone the exact costs claimed here. Mr. Crist' Rebuttal Testimony specifically stated that he reviewed the Companies' support for its charges, which of course, included the workpapers submitted by Ms. Grace. The Companies' testimony, exhibits and workpapers provided no explanation of how the Companies had determined that each of the line items in its schedule were truly incremental and would not have existed without the CFY program, so he then spent five full pages of testimony reviewing responses to data requests asking for support for the Companies' figures. He concluded that there was no supporting evidence. Mr. Crist, RGS Ex. 2.0 at 9-14. RGS believes that the workpapers contain absolutely no data that support the Administrative charges. Thus, there was nothing “fatal” about RGS failing to provide the Companies’ workpapers as an exhibit in the case. If the Companies had thought that those workpapers would have supported its position, they certainly would have done so themselves. It is unclear to RGS why the Staff brief references Ms. Grace’s workpapers, since none of the Staff witnesses or Ms. Grace herself pointed to anything in the workpapers to support the Administrative Costs. What is clear is that the workpapers contain no evidence supporting the Administrative Costs.

In any event, as noted above, even if the Companies were able to prove that some of these administrative costs were truly incremental costs that would not exist had the Companies not created the CFY program, and even if there were no offsetting savings from the CFY customers leaving the Companies’ sales service, such incremental costs should be shared by all customers eligible to take CFY service.

c) Staff

Staff sees merit in the Utilities’ arguments, and declines to support RGS’ proposals because the record indicates that Ms. Grace provided at least partial justification of these costs in her *workpapers*. Ms. Grace’s complete response to the RGS data requests, which Mr. Crist did not put in his narrative testimony but was attached to his testimony as an exhibit, states, “See Ms. Grace’s direct testimony, exhibits and workpapers for the support for the Riders FST, SST, P and AGG charges. The requested information is not maintained in and cannot be retrieved in the requested level of detail.” RGS Ex. 2.3, Companies’ Responses to RGS Data Request 1.42. Staff notes that RGS failed to even address these supporting workpapers in its testimony. Staff believes this failure is fatal to RGS case.

While Staff witness Sackett supported a similar proposal in Nicor Gas’ last rate case, Docket 08-0363, it is clear that his support for this treatment was linked to his support for the MOU. Furthermore, this issue was uncontested in that case because Nicor Gas agreed to this treatment before Staff accepted a settlement on all Customer Select issues. In contrast, the Companies have contested this treatment of administrative costs.

Therefore, Staff continues to recommend that the administrative charges proposed by the Companies be approved by the Commission. However, if the Commission orders the workshop advocated by Staff above, then the Administrative Costs should be reviewed in that context.

d) Commission Analysis and Conclusion

At this point, the Commission adopts the Utilities’ position to recover these costs through specific charges to suppliers. Because the Commission has adopted Staff’s position to hold workshops, the Administrative Costs are matters that can be reviewed in that forum. See the discussion of the adoption of the workshop process above.

4. Rider SBO Issues

a) Utilities

RGS argues that Rider SBO should be revised in two ways. First, RGS witness Crist states that customers in payment arrears to the Utilities should not be removed from receiving a Rider SBO bill. Second, he states that there should be a mechanism allowing a customer's credit on its utility bill to be transferred to the supplier.

The Utilities explain that Rider SBO describes the terms and conditions under which a supplier may choose to issue a single bill that includes utility charges. NS-PGL Ex. JM-1.0 at 14. Turning to RGS' first request concerning customer arrearages, customers leaving budget billing when they switch to CFY seems to be a significant part of RGS' concern. RGS Ex. 1.0 at 24-25. According to the Utilities, however, this is not a basis for changing Rider SBO. First, a customer who is participating in the Utilities' budget billing plan may receive a Rider SBO bill. NS-PGL Ex. JM-2.0 at 5. Second, it is common for an alternative supplier to request that the Utilities remove a customer from the budget payment plan. NS-PGL Ex. JM-1.0 at 15. The alternative supplier is, therefore, in control of the situation and can remedy the issue, for example, by ensuring that the arrearage is paid. NS-PGL Ex. JM-2.0 at 6. Third, the origin of the Rider SBO provision at issue was that, in Dockets 01-0469 and 01-0470, when the Utilities introduced Rider SBO, suppliers raised issues over collecting utility arrearages that, in their opinion, would create customer confusion and have a negative impact on competition. The suppliers also argued that the Utilities needed to address receivables risk under Rider SBO. The Utilities did so by including terms and conditions in Rider SBO that insulated suppliers from receivables risk. The Commission agreed with the Utilities' proposal. *North Shore Gas Company*, Docket 01-0469 at 26 Order, Mar. 5, 2002; *The Peoples Gas Light and Coke Company*, Docket 01-0470 at 30 Order, Mar. 5, 2002.

Moreover, the Utilities state that a customer with arrearages to the Utilities is in danger of having service discontinued. Issuing bills and using bill messages to try to address the arrearage problem is facilitated by the Utilities controlling the production and issuance of the bill. Staff's opinion that the supplier has an incentive to collect arrearages is not the point. Collection is, of course, one of the Utilities' concerns, but the customer may also have a right to payment arrangements (*see, e.g.,* 83 Ill. Admin. Code §§280.110 and 280.135) or be eligible for assistance that will prevent service discontinuance ("No public utility shall disconnect service for nonpayment of a bill until the lapse of six business days after making the notification required by subsection (b)(1) of this Section so as to allow the customer an opportunity to: … 2) Contact a governmental or private agency that may provide assistance to customers for the payment of public utility bills." 83 Ill. Admin. Code §280.135(c)). The Utilities use the bill to convey some of this information.

Turning to RGS' second request concerning credit balances, RGS describes this as a matter of complying with the customer's requests. But, the Utilities note, it is the supplier, and not the customer, making the request. RGS was asked to offer evidence to support that it is the case that suppliers' agency authority encompasses such a request. RGS' witness provided no agreement forms and offered a single quotation from one supplier's agreement. RGS Ex. 2.4; Tr. at 576-579. The undefined offer that the supplier provide an affidavit offers little protection to the Utilities. In addition, the costs involved to make the system programming changes should be considered. The Utilities estimated more than 500 hours would be needed to implement system programming changes. NS-PGL Ex. JM-2.0 at 7. Furthermore, the customer may have legitimate reasons to have the Utilities refund that credit and not transfer it to the supplier. NS-PGL Ex. JM-1.0 at 17.

For both Rider SBO issues, RGS has not met its burden of showing that a change to the Rider SBO is required. Moreover, for both issues, the supplier is able to address the situation directly with the customer with whom it has a contractual relationship, whether by ensuring that arrearages are paid before taking actions that could jeopardize the customer's receipt of Rider SBO bills or by arranging for the customer to transfer a credit to it. The Commission should reject RGS' proposals.

b) RGS

As a general rule, RGS states, small commercial and residential customers understandably prefer less paperwork associated with their natural gas service. Many CFY customers also prefer to interact with their CFY supplier rather than PGLC/NSG, in part because the CFY supplier can offer a wider range of products and services, including non-gas commodity products and discounts for multiple purchases. As a result, many CFY customers prefer to receive a single bill from their CFY supplier that combines the CFY commodity charges, charges for other products or services, and the PGLC/NSG distribution charges.

The Companies allow for this type of CFY supplier billing under theirSBO service. Unfortunately, the Companies' SBO operational rules create unnecessary problems for customers on the Companies' budget plan that have a debit balance, and all types of customers that have credit balances with the Companies. In each instance, the Companies' rules unnecessarily and inappropriately prevent customers from being able to make choices regarding their billing options.

a. Customers With A Debit Balance

Due to a quirk in the Companies' systems, customers with debit balances under the Companies' budget plans effectively are precluded from taking service under the Supplier Billing Option. Under the current rules, customers that are more than 60 days in arrears with the Companies are ineligible for the SBO. However, when a customer with a debit balance leaves the budget plan and transfers to a CFY provider, a "true up" amount is owed by the customer to the Companies, but the customer will not receive the Companies' "true up" until the second month after switching. Thus, if the customer wants to receive a single bill from its supplier, the customer will receive an SBO bill for their first month of service from the CFY supplier and in the next billing period the customer would be kicked off of SBO and would receive either a dual bill (from the CFY supplier and utility), or a single bill from the utility. Needless to say, this change in billing causes confusion and frustration for the customer who wanted to receive a single bill from its supplier, and causes issues for the CFY suppliers that have built their systems and products to support single billing instead of dual billing.

A straightforward solution to this problem would be to allow customers in arrears to be swerved under the SBO. Mr. Crist pointed out that having customers on SBO that are in arrears with the Companies would not inhibit the Companies' ability to collect what is owed them because the Companies still could follow their normal collections procedures. Additionally, the CFY suppliers would have an incentive to collect all of the Companies' balance from their customers because payments that CFY suppliers receive from customers are first applied to the Companies' balances and then to the CFY suppliers' balances. (*See* Mr. Crist, RGS Ex. 2.0 Rev at 18:402-08.) Companies witness Mr. McKendry acknowledged this fact on cross-examination. *See* Tr. at 308-309. Thus, under the existing rules, if the CFY suppliers wish to be paid by the customers, the CFY supplier first must collect all balances owed to the Companies.

The Companies objected to Mr. Crist's recommendation. Mr. McKendry first argued that it is the CFY supplier that removes customers from budget billing, not the Companies. NS-PGL Ex. JM-1.0, at 15-16. Of course, its is the customer's choice that the RGS proposal seeks to recognize – not that of the suppliers. The Companies' argument actually makes the point RGS is trying to make here – the Companies' rules prevent CFY suppliers from offering the SBO to customers that have a debit balance, which unnecessarily limits customers' ability to choose their own billing options.

Mr. McKendry also argued that if the Companies cannot bill SBO customers with debit balances, then they cannot use bill inserts to aid in collection of those balances. NS-PGL Ex. JM-1.0, p. 16. However, Mr. Crist pointed out that according to the plain language of Rider SBO, Page 3, Section D, paragraph (4), CFY suppliers are <u>required</u> to print "other information provided by the Company" on the customer's bill. The Companies may send up to three bill messages every month and the CFY suppliers print those messages. On cross-examination, Mr. McKendry again acknowledged this fact. *See* Tr. at 312-313.

The Companies argue that the provision at issue was created in Dockets 01-0469 and 01-0470, in response to suppliers concern over collecting utility arrearages. Regardless of that history, CFY suppliers have now had experience with this provision and see that it hampers their ability to serve customers. As stated by the Staff:

> Staff believes that the supplier should have the option of keeping those customers on SBO if they are willing to shoulder that risk. Since the Company charges are paid first, the supplier has just as much of an incentive to collect as the Companies would.

Staff Brief at 201.

Mr. Crist agrees with the rational provided by the Staff, stating that "the Alternative Supplier is highly motivated to collect the utility charges." RGS Ex. 2.0 (Rev.), at 18:408-09. In any event, the fears expressed by the Companies have not prevented Nicor from allowing customers who are in arrears to participate in the single bill option available to its choice program and that program continues to work well. *See* Mr. Crist, RGS Ex. 2.0 (Rev.), at 19:418-20.

Finally, RGS points out that Nicor allows customers in arrears to participate in its choice program and use that company's single bill option.

b. Customers With A Credit Balance

The Companies' rules also cause problems for customers that switch to CFY service with a credit balance that is in the hands of the Company. The Companies' current rules do not provide a mechanism to transfer this credit to the customer's CFY supplier, even in situations where the customer has requested the transfer in writing. This problem occurs most often with customers on budget plans that have built up a credit balance, but even other customers also may have deliberately or inadvertently built up a credit balance.

Instead of complying with the customers' requests to transfer the credit balance to the CFY suppliers, the Companies issue a refund check to those customers who have a credit balance and choose the SBO. This often causes customer confusion, and requiring the customer to deposit the utility's check and then write a personal check to the CFY supplier. This burdensome process requires manual intervention by the customer, the CFY supplier and the utility. Additionally, the customer may be incurring late fees and collections activity by the CFY supplier while waiting for these funds to be issued and cleared.

This rule also places CFY suppliers that offer single billing under Rider SBO at a competitive disadvantage because CFY suppliers that choose to bill on the utility bill do not have this issue. The Companies will automatically allocate any credit balances to CFY suppliers that bill on the utility bill. Thus, this failure to provide CFY suppliers using SBO with a customer's credit balance implicitly favors continued billing on the utility bill.

RGS proposes that customers' who request that credit balances be paid to their CFY supplier be honored. Mr. Crist recommended that the Companies adopt the same process used by Nicor Gas. Under that utility's program, within 5 days of receipt of a billing file from Nicor Gas, the Customer Select supplier can request a transfer of customer credit balances on the utility account for amounts owed to the alternative supplier. The CFY supplier is required to be in possession of fully executed authorization from the customer granting such permission to the CFY supplier. The utility then processes the request systematically, and transfers the credit balance for those customers. The process is automated, and the customers avoid the confusion and inconvenience of receiving a check from the utility and issuing a payment to the CFY supplier.

The Companies objected to RGS's proposal. First, Mr. McKendry expressed concern that the Companies had no way of knowing if a customer's agency agreement with its CFY supplier contains explicit authorization to transfer credit balances. NS-PGL Ex. JM-1.0 at 17. As noted by Mr. Crist, however, the Companies do not ask for and CFY suppliers do not supply the Companies with copies of each and every customer agreement. (RGS Ex. 2.0 Rev at 20.) Rather, the control over the CFY suppliers' activities is that they must adhere to the Companies' rules for providing Rider SBO service and to the terms it has agreed to with their customers. *Id.* He also noted that as a matter of general practice, CFY suppliers will provide the Companies with an affidavit with every request for a credit transfer that states they have an agency agreement with the customer to do so. *Id.*

The Companies argue that the reason they refuse to honor the customers' requests is because they have no ready way to verify if a supplier's agreement with the customer includes provisions permitting such a transfer. The Companies add that they do not review each customer's agreement to determine what rights a supplier may have to manage a customer's account and the customer may have legitimate reasons to have the Utilities refund that credit and not transfer it to the supplier. The Commission Staff agrees with the Companies' rationale, adding that it would be an additional administrative burden to the Companies. Mr. Crist added that Alternative Suppliers supply the Companies with an affidavit with every request for a credit transfer that states they have an agency agreement with the customer to do so. (RGS Ex. 2.0 Rev at 20.) This affidavit, along with the understandable desire of Alternative Suppliers to avoid violating their customers' trust, the Companies' CFY rules, the PUA and possibly fraud statutes, should suffice to alleviate any concerns that the customer might not want their credit balance transferred to their CFY supplier.

Mr. McKendry also expressed skepticism that it was worth the Companies effort to automate the credit refund process if there were only a few such requests. NG-PGL Ex. JM-1.0 at18. In response, Mr. Crist stated that he was aware of one CFY supplier with 500 customers that had a credit balance. (RGS Ex. 2.0 Rev at 21:457-63.) On cross-examination, Mr. McKendry admitted that he knew about this issue before submitting his surrebuttal testimony and that he did not take issue with the information provided. Tr. at 300-301.

As for the concern about administrative costs, Nicor has found that whatever administrative costs it incurs are an acceptable price to pay in order to honor the wishes of its customers for the disposition of their credit balances. (RGS Ex. 2.0 Rev. at 20-21.) The Companies should do the same.

c) Staff

RGS witness Mr. Crist raises two issues regarding service under Rider SBO, which is the Companies' SBO Service. The first regards the Companies' refusal to allow customers with arrearages with the Companies of greater than 60 days receiving service under this rider. Staff believes that the supplier should have the option of keeping those customers on SBO if they are willing to shoulder that risk. Since the Company charges are paid first, the supplier has just as much of an incentive to collect as the Companies would. Despite Mr. McKendry stating that "Alternative suppliers are not obligated, under Rider SBO, to accept or print bill messages" (NS-PGL Ex. JM-1.0, at 16), he eventually acknowledges that Rider SBO (RGS Cross McKendry Ex. 38) does require the supplier to put "other information provided by the Company" on the bill, so his objection is unfounded. Tr. at 312-313. Therefore, Staff believes that the Commission should find that the supplier under Rider SBO can continue to serve their customers in arrears under the rider. However, if the Commission orders the workshop advocated by Staff above, then the service to customers in arrears issue could be considered in that context and not changed here.

The second Rider SBO issue raised by Mr. Crist is the treatment of those customers that sign up for CFY and have a credit balance with the Companies. He proposes that the balance which is currently refunded to the customer be transferred automatically to the supplier's account. RGS Ex. 1.0, at 26-27. Companies witness McKendry also rejected this proposal because it is more complicated than the current process. He states that it would be difficult for the Companies to verify each supplier contract to ensure that the customer had made such a request. NS-PGL Ex. JM-1.0 at 16-17. He also claimed that it would require significant re-programming to automate this process. NS-PGL Ex. JM-2.0 at 6. No one refuted this claim.

Staff does not support transferring a credit balance for a transferred customer to the supplier's account unless there is a specific provision in the Companies' contract with its customers regarding credit balances. Staff would not support requiring such a provision as it is inconsistent with the handling of customer termination of budget billing and would be an unnecessary additional administrative burden to the Companies . The Companies must continue to return the balance directly to those customers leaving the budget billing plan. Just because the marketers claim that provision exists or could exist in their contracts with the customer, there is no way for the Companies to verify that claim for each case.

d) Commission Analysis and Conclusion

We do not resolve these issues at this time. The Commission believes that consumer concerns raised by Staff and the Utilities are ideally suited to the workshop process that we here established.

5. New Customer Issues

a) Utilities

The Utilities note that RGS proposes that the Utilities' processes applicable to new customers be revised to allow new customers to take CFY service immediately and not first apply for and take service as a sales customer. The Utilities' process, applicable to all service applicants, is that an applicant starts receiving service only when the gas is turned on or, if the service is left on by the previous customer, when the Utilities obtain a meter reading. This requires scheduling a field service order. The account is "pending" until the gas is turned on. The account becomes "active" once the service order is complete. NS-PGL Ex. JM-1.0 at 20. The Utilities do not accept CFY enrollment requests that suppliers submit when customers' accounts are "pending" for practical reasons. Many things can change between the service request and when service orders are scheduled. For example, customers may cancel the service request before the scheduled turn-on date or re-schedule the turn-on date. Also, the Utilities are concerned that activating customers' accounts immediately in supplier's pools is inconsistent with Senate Bill 171's requirement that allows customers a minimum of 10 business days from the Utilities' notice to rescind contracts with their suppliers. *Id*. at 21.

Staff and RGS both argue that Senate Bill 171 does not apply to new customers. The practical problem being the fundamental difficulty of processing a request for transportation service for a person who is not yet a customer. Staff's position is, apparently, that a customer may take transportation service from day 1, but the utility must still provide the customer with notice that he is taking transportation service and the customer would then have ten business days to rescind its agreement, without penalty. Staff's argument distinguishes subsection (g)(7) from (g)(6) of Section 19-115 of the Act. 220 ILCS 5/19-115(g). Subsection (g)(6) requires a utility to give a customer notice, within two business days of receipt of a supplier request, of a switch. The customer then has ten business days to rescind its agreement. Subsection (g)(7) does not use the term "switch" but it refers to the "gas utility notice" and the ten business day rescission period. Staff's distinction between the two subsections is confusing. Subsection (g)(6) is describing the gas utilities' obligations and subsection (g)(7) is describing the suppliers' obligations. The "gas utility notice" in subsection (g)(7) seems to be the notice described in subsection (g)(6). If subsection (g)(6) does not apply to new customers, then subsection (g)(7) does not apply to new customers. If one applies to new customers, then both apply to new customers.

Staff's interpretation also creates ambiguity. Subsection (g)(7) does not have the two business day period tied to notice from the supplier, so, while Staff is arguing that the Utilities must give notice, neither Staff nor subsection (g)(7) gives the timing for the notice. Do the Utilities give notice within two business days of receipt of a supplier request, even if there is not yet a customer to whom the Utilities may give notice because service is not yet activated? If the Utilities' notice is sent two weeks after the customer is activated on the system and is receiving transportation service, does that customer get ten business days to rescind, without penalty, the supplier contract? Staff's interpretation of Section 19-115(g) of the Act offers no guidance.

The Utilities' believe their practice concerning new customers is reasonable, and the Commission should not order a change. However, if the Commission disagrees, the Utilities urge the Commission to clarify that neither subsection (g)(6) nor (g)(7) of Section 19-115 of the Act applies to new customers.

b) RGS

The Companies prohibit customers that are new to their service territories from immediately receiving service under the CFY program. Instead, they require a customer to take sales service from them for one month before they can be activated as a CFY customer. According to RGS, this causes confusion for customers who are establishing service at a new premise because they expect that service to begin when their gas account becomes active. Instead, the customer receives a utility bill when they are expecting to receive a consolidated Alternative Supplier bill the first month. Under the Utilities process, the customer finally receives the Alternative Supplier single bill only in their second month of service.

RGS witness Crist testified that the Companies should follow their customers' direction and initiate service with the Alternative Supplier immediately upon request, and cease their practice of requiring a customer to take sales service for one month before they can activate in the CFY program.

Utilities witness McKendry argued that the Companies should be able to prohibit new customers from participating in the CFY program. His first argument is that new customers may end up having gas turned on at a different time than originally planned and until that time, the Companies will not know when the customer will become active in the supplier's pool. NS-PGL Ex. JM-1.0 at 21. Mr. Crist characterized this argument as "akin to saying that it is just company policy." RGS Ex. 2.0 Rev at 22. At hearing, Mr. McKendry admitted that a customer would never receive a bill until an account went to "active" status. Tr. at 275. Thus, RGS asserts that the Companies have implemented an anti-competitive policy to address a problem that does not actually exist.

Mr. McKendry's second argument is: "Activating customers' accounts immediately in supplier's pools is inconsistent with allowing customers a minimum of 10 business days from the Utilities' notice to rescind contracts with their suppliers." NS-PGL Ex. JM-1.0 at 21. SB 171's notice requirements and rescission restrictions, however, apply to switches from one supplier to another, not to a new customer. On cross-examination, Mr. McKendry agreed with this point. Tr. at 281. Thus, the Companies are not required to wait 10 business days before placing new customers on the CFY program. They can do so immediately.

Staff supports RGS's position and adds that SB 171 also provides that an "alternative gas supplier shall provide each customer the opportunity to rescind its agreement without penalty within 10 business days after the date on the gas utility notice to the customer." 220 ILCS 5/19-115(g)(7). Staff therefore suggests that the Commission indicate that this language necessarily requires utilities to provide notice that a request has been received to begin new service as a transportation customer. RGS supports the Staff's additional recommendation.

c) Staff

RGS witness Crist proposed that customers should be allowed to begin service with Peoples Gas/North Shore as a transportation customer rather than being forced to start as a sales customer and subsequently switch to a transportation customer. Companies witness McKendry opposes this proposal because a customer cannot sign up for CFY while its service request is pending. He also claimed that the most important reason why he rejected the proposal is that it would be inconsistent with language added to 220 ILCS 5/19-115(g)(7) by Senate Bill 171 (enacted as Public Act 95-1051). NS-PGL Ex. JM-1.0 at 20-21. Specifically, Mr. McKendry claimed that RGS's proposal "is inconsistent with allowing customers a minimum of 10 business days from the Utilities' notice to rescind contracts with their suppliers. While Staff has not seen the parties' legal arguments on this issue and reserves the right to respond to those arguments in its reply brief, Staff does not see a legal impediment to RGS' proposal. A right to rescind service with an alternative gas supplier is neither prohibited nor prevented by allowing a customer to start utility service as a transportation customer.

Companies witness McKendry may also be referring to language in paragraph 6 of subsection (c) of Section 19-115 (*see* Tr. at 277-281) that not only requires the utility to provide written notification of a switch to a customer, but also prevents the utility from switching service until 10 days after such notice. 220 ILCS 5/19-115(g)(6). While Staff would agree with the implication in Mr. McKendry's argument that a customer's right to rescind supply service with an alternative gas supplier applies whether the customer is changing an existing service or requesting new service (*see* 220 ILCS 5/19-115(g)(7)), the language prohibiting a utility from switching service until 10 days after notice of a switch is not applicable to a request for new service as a transportation customer because the prohibition at issue specifically refers to performing a switch and does not refer to new service. The Commission should confirm that Section 19-115(g)(6) does not prevent customers from taking new service as transportation customers and does not prohibit service to new transportation customers from commencing on less than 10 days notice. Staff further notes that paragraph 7 of subsection (g) of Section 19-115 provides that an "alternative gas supplier shall provide each customer the opportunity to rescind its agreement without penalty within 10 business days after the date on the gas utility notice to the customer." 220 ILCS 5/19-115(g)(7). Thus, the Commission should also indicate that this language necessarily requires utilities to provide notice that a request has been received to begin new service as a transportation customer.

However, if the Commission orders the workshop advocated by Staff above, then the New Customer Issues could be considered in that context and not changed here.

d) Commission Analysis and Conclusion

This issue will also be added to the workshop process that the Commission established above. Any resolution that is ultimately reached by the participants must consider and comply with the Act's requirements.

6. Customer Switching Issues

a) Utilities

Mr. Crist argues that the Utilities' customer switching practice delays the customer switch for an extra nine days beyond what is required by law. He recommends that the Commission require the Utilities to reduce the period from 19 to the 10 days that he states is required by Senate Bill 171. RGS Ex. 1.0 at 644-645. Mr. Crist's recommendation is inconsistent with Senate Bill 171 and must be rejected. First, the statutory contract rescission period is 10 business days and not calendar days, as he acknowledged. 220 ILCS 5/19-115(g)(6); Tr. at 573; NS-PGL Ex. JM-1.0 at 19. Second, Mr. Crist appears not to recognize that the event that triggers the start of the 10-business day period is the Utilities' notice to the customer. 220 ILCS 5/19-115(g)(6); Tr. at 573; NS-PGL Ex. JM-1.0 at 19. Third, the Utilities have two business days from receiving the supplier request to send the notice to the customer. 220 ILCS 5/19-115(g)(6); NS-PGL Ex. JM-1.0 at 418-419. Fourth, this 12-business day period necessarily includes two weekends, *i.e.*, four more calendar days. NS-PGL Ex. JM-2.0 at 7. Finally, many months include a State holiday. *Id*. at 7.

The Utilities' 19-day period is a reasonable and narrow window that ensures compliance with Senate Bill 171, the relevant portion of which is codified at 220 ILCS 5/19-115(g)(6). In contrast, Mr. Crist's comparison of 19 to 10 calendar days to claim that the Utilities improperly extend the period by nine days is clearly incorrect, and his recommendation to reduce the window to 10 days would be contrary to the law.

RGS incorrectly asserts that the Utilities picked the most extreme example they could find. The example did not assume a four-day holiday. It assumed that Thanksgiving was a State holiday, but it treated the day after Thanksgiving as a business day. Hence, the Utilities' example was receipt of the supplier's request on Wednesday. It sent notice two business days after that, as required by law, and one of those business days was the day after Thanksgiving. At best, the Senate Bill 171 process will take 16 days -- two business days for notice plus ten business days for the rescission period. Any twelve business day period necessarily includes two weekends. NS-PGL Ex. JM-1.0 at 19; NS-PGL Ex. JM-2.0 at 7. Any switch request received on a Thursday or Friday will encompass three weekends (six additional calendar days), even with no State holidays. A 19-day presumption is reasonable. It is likewise reasonable for Utilities that serve over 900,000 customers who are eligible for the CFY program to have an automated process to ensure that all customers receive the ten-business day window to rescind the contract before the Utilities place the customer on transportation service.

b) RGS

The Companies' signup process causes unnecessary delays and confusion with the customer regarding their enrollment into the CFY program. The customers are delayed from beginning service with the Alternative Supplier after they have made their decision because the Companies arbitrarily delay a customer's activation in the program to the first meter reading that occurs after a minimum period of 19 days following the customer's sign up date.

RGS agrees that implementation of Bill 171 will cause some delay because that bill provides customers with the right to rescind the agreement with their Alternative Supplier within 10 business days after receiving notice from the utility of a switch request. Prior to the enactment of SB 171, the Companies had a process in place where a customer could be activated on the first meter read after an 8-day wait period. In order to be in compliance with Senate Bill 171, the 8-day period needed to be adjusted to delay activation until the 10 business day rescission period had lapsed, in case the customer decided to rescind. But the Companies have gone much further and extended the waiting period to 19 days.

RGS asserts that the Utilities based the waiting period on the most extreme example they could find – a customer enrolls the day before a four day holiday – the Wednesday before Thanksgiving. NS-PGL Ex. JM-1.0 at 19. A more realistic and legally compliant waiting period would be based on the words in the statute - ten business days from the issuance by the utility of notice to the customer.

c) Staff

RGS witness Crist proposed that customers be allowed to switch from sales service to CFY right up to the 10 *business*-day window required by Senate Bill 171 instead of the 19 calendar-day process the Companies adopted after the passage of the law. RGS Ex. 1.0, at 28.

Companies witness McKendry rejected this proposal because the Companies' process ensures that in the extreme case a customer may need 19 calendar days to achieve the 10 *business*-day rescind period mandated by the law. NS-PGL Ex. JM-1.0 at 18-20.

The Companies' process is automated and arbitrary. RGS Cross Ex. McKendry38. Furthermore, it goes beyond the requirements of the new requirements enacted pursuant to Senate Bill 171. RGS Cross Ex. McKendry-10. Therefore, it should not remain at 19-calendar days. Staff believes that the policy should be rewritten to reflect the language in the law. This would result in "up to 19 days" but only in the extreme circumstance. However, if the Commission orders the workshop advocated by Staff above, then the Customer Switching Issues could be considered in that context and not changed here.

d) Commission Analysis and Conclusion

This issue will also be addressed in the workshop process that the Commission has here established. The participants should be prepared with, and able to address, statutory construction of the relevant portions of the Act at the workshops.

7. Administrative Improvements to Supplier Billing System and PEGASys System Improvements

a) Utilities

RGS contends that the Utilities should state inventory or storage volume information on the monthly bill. The Utilities state that they provide that information through reports available to suppliers via PEGASys™ at any time. NS-PGL Ex. JM-1.0 at 21. The requested information is readily available, and there is no basis for the Commission to order the Utilities to provide the information in a different format.

Mr. Crist also stated that the Utilities should make improvements in their supplier billing and PEGASys™ system. RGS Ex. 1.0 at 9. There is no explanation as to what PEGASys™ system improvements RGS is seeking. Consequently, there is nothing on which the Commission may act.

Staff supports the request for added information on the bill, but Staff acknowledges that the information is already available to suppliers. *Id*. The Commission's bill format rules do not require this result. 83 Ill. Admin. Code §500.330. With PEGASys™, suppliers may readily get whatever information that particular supplier wants or needs and ignore what is superfluous. The request that the Utilities provide exactly the same information in the form of a new bill format, which all CFY suppliers would receive and not merely the three in this proceeding, is redundant and unnecessary and should be rejected.

b) RGS

Mr. Crist had several recommendations for administrative improvements to the CFY program. First, the Companies do not state an inventory volume or storage capacity volume on the monthly bill. He testified that such knowledge is important for

CFY suppliers so they can know precisely where they stand and are better equipped to properly manage the complex job of supply procurement. He stated that the Companies provide some limited information on the PEGASys, but that system never really picks up changes an Alternative Supplier makes to the daily nominations. Therefore it does not provide a complete picture. He therefore recommended that the Companies should provide this important information within PEGASys, in a useful manner.

Mr. Crist testified that there are four components of storage data that Alternative Suppliers require to properly manage their business:

(1) the Storage Balance (which is available on PEGASys™);

(2) the Storage Adjustment Cumulative (which is updated once a month and available on PEGASys™);

(3) the Deposit Balance (which is on the bill); and

(4) the Carry Forward amounts (which also is on the bill).

These are the four important storage data items that could be placed on the supplier bill and eliminate the manual hunting of data that suppliers must undertake to understand and manage their storage positions. (RGS Ex. 2.0 Rev at 23.)

RGS believes that this is one area where workshops between the Companies and CFY suppliers may be useful. During those workshops, CFY suppliers can provide feedback on PEGASys™ and the Companies can provide information on their own limitations in implementing CFY supplier wishes.

c) Staff

RGS witness Crist proposed that the Companies print certain information on the supplier bills. He listed four pieces of information that suppliers would like in that convenient format, two of which are already included (deposit balance and carry forward volume). The other two (inventory volume and storage capacity volume) are only available on the PEGASys™. The Companies rejected this proposal because all this information is available to the suppliers on PEGASys™. NS-PGL Ex. JM-1.0 at 21-22. Staff recommends that the Commission direct the Companies to provide the information requested by the suppliers in the manner requested. While the information is already available, the record establishes the convenience of receiving the information in the manner requested and does not establish any significant administrative burden to provide the information as requested. However, if the Commission orders the workshop advocated by Staff above, then the Administrative Improvements could be considered in that context and not changed here.

d) Commission Analysis and Conclusion

The Commission notes that this is the one area where RGS agrees that the workshop process would be useful. However, the Commission believes that it would be more productive to allow the parties to address all the relevant issues at once which will facilitate the workshop process and likely lead to a better end.

XIV. Findings and Ordering Paragraphs

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) Peoples Gas is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the the Act

(2) North Shore is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the the Act

(3) the Commission has jurisdiction over the parties and the subject matter herein;

(4) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; the Appendices attached hereto provides supporting calculations;

(5) the test year for the determination of the rates herein is found to be just and reasonable should be the 12 months ending December 31, 2010; such test year is appropriate for purposes of this proceeding;

(6) the $2,524,981,000 original cost of plant for Peoples Gas at December 31, 2007, as reflected on the Company's Schedule B-5, Page 1 of 2, Line 14, Column F; and the $398,956,000 original cost of plant for North Shore at December 31, 2007, reflects the amount on the Company's Schedule B-5, Page 1 of 2, Line 12, Column F, after taking into account the capitalized incentive compensation costs the Commission disallowed in each company's prior rate case. The amounts are unconditionally approved as the original costs of plant;

(7) for the test year ending December 31, 2010, and for the purposes of this proceeding, Peoples Gas' original cost rate base with adjustments is $1,201,426,000.

(8) for the test year ending December 31, 2010, and for the purposes of this proceeding, North Shore's original cost rate base with adjustments is $183,103,000;

(9) a just and reasonable return which Peoples Gas should be allowed to earn on its net original cost rate base is 8.05%; this rate of return incorporates a return on common equity of 10.23% and costs of long-term debt of 5.28%, with a just and reasonable capital structure of 56% common equity and 44% long-term debt;

(10) a just and reasonable return which North Shore should be allowed to earn on its net original cost rate base is 8.19%; this rate of return incorporates a return on common equity of 10.33% and costs of long-term debt of 5.48%,

with a just and reasonable capital structure of 56% common equity and 44% long-term debt;

(11) Peoples Gas' rate of return set forth in Finding (9) results in approved base rate net operating income of $96,715,000;

(12) North Shore's rate of return set forth in Finding (10) results in approved base rate net operating income of $14,999,000;

(13) Peoples Gas' rates, which are presently in effect, are insufficient to generate the operating income necessary to permit Peoples Gas the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(14) North Shore's rates, which are presently in effect, are insufficient to generate the operating income necessary to permit North Shore the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(15) the specific rates proposed by Peoples Gas in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; Peoples Gas' proposed rates should be permanently canceled and annulled consistent with the findings herein;

(16) the specific rates proposed by North Shore in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; North Shore's proposed rates should be permanently canceled and annulled consistent with the findings herein;

(17) Peoples Gas should be authorized to place into effect tariff sheets designed to produce annual revenues of $530,663,000, including base rate and rider revenues other than PGA and coal tar revenues, which represents a gross increase of $69,803,000; such revenues will provide Peoples Gas with an opportunity to earn the rate of return set forth in Finding (9) above; based on the record in this proceeding, this return is just and reasonable;

(18) North Shore should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $79,067,000, including base rate and rider revenues, which represent a gross increase of $13,867,000; such revenues will provide North Shore with an opportunity to earn the rate of return set forth in Finding (10) above; based on the record in this proceeding, this return is just and reasonable;

(19) the determinations regarding cost of service and rate design contained in the prefatory portion of this Order are reasonable for purposes of this proceeding; the tariffs filed by North Shore and Peoples Gas should incorporate the rates and rate design set forth and referred to herein;

(20) as required in this Order, under the discussion of Rider ICR, Peoples Gas shall adopt and implement Rider ICR as proposed and with the inclusion of the recommended language changes proposed by Staff and accepted by Peoples Gas;

(21) as discussed in this Order, Staff's three modernization proposals for Peoples Gas are rejected;

(22) as required in this Order, under the discussion of Rider FCA, North Shore should include in its compliance filing, effective base rates that include franchise costs in its test year revenue requirements and base rates that would become effective May 1, 2010, that remove franchise costs from its test year revenue requirements;

(23) as required in this Order, under the discussion of Uniform Numbering of Service Classifications in Rate Design, the Utilities should evaluate the feasibility of uniform service classification numbering and address this in their next rate case;

(24) as required in this Order, under the discussion of Rider VBA in Rate Design, the Utilities should provide, with their compliance filing, the Rider VBA "rate case margins" and "rate case customers" resulting from the approved revenue requirements;

(25) as required in this Order, under the discussion of Rider VBA in Rate Design, the Utilities should each annually prepare a report on their rates of return and the effect of that return of Rider VBA and submit it to the Commission and Staff at the same time they file petitions seeking initiation of an annual reconciliation proceeding to determine the accuracy of the Rider VBA Reconciliation Adjustment;

(26) as required in this Order, under the discussion of Intra-Day Nomination Rights, the Utilities should revise their transportation tariffs to describe the terms and conditions of the Evening Nomination Cycle; describe the current practice related to handling nomination changes required by upstream pipeline cuts;

(27) as required in this Order, under the discussion of Rider SST, the Utilities should work collaboratively with the Commission Staff and other stakeholders to develop proposals to unbundle their transportation storage services from their standby services;

(28) as required in this Order, under the discussion of Super Pooling on Critical Days, the Utilities are required to allow super-pooling as adopted herein;

(29) as required in this Order, under the discussion of the Small Volume Transportation Program, Staff is directed to commence the workshops as proposed;

(30) the determination regarding cost of service and rate design contained in the prefatory portion of this Order are reasonable for purposes of this

proceeding; the tariffs filed by North Shore and Peoples Gas should incorporate the rates and rate design set forth and referred to herein; and

(31) new tariff sheets authorized to be filed by this order should reflect an effective date consistent with the requirements of Section 9-201(b) as amended.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets presently in effect rendered by The Peoples Gas Light and Coke Company and North Shore Gas Company are hereby permanently canceled and annulled, effective at such time as the new tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general rate increase, filed by The Peoples Gas Light and Coke Company and North Shore Gas Company on March 9, 2007 are permanently canceled and annulled.

IT IS FURTHER ORDERED that the $2,524,981,000 original cost of plant for Peoples Gas at December 31, 2007, reflects the amount on the Company's Schedule B-5, Page 1 of 2, Line 14, Column F; and the $398,956,000 original cost of plant for North Shore at December 31, 2007, reflects the amount on the Company's Schedule B-5, Page 1 of 2, Line 12, Column F, after taking into account the capitalized incentive compensation costs the Commission disallowed in each Company's prior rate case; the amounts are unconditionally approved as the original costs of plant.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company are authorized to file new tariff sheets with supporting workpapers in accordance with Findings 17 and 18 of this Order, applicable to service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Peoples Gas shall adopt and implement Rider ICR as proposed and with the inclusion of the recommended language changes proposed by Staff and accepted by Peoples Gas;

IT IS FURTHER ORDERED that North Shore shall include in its compliance filing, effective base rates that include franchise costs in its test year revenue requirements and base rates that would become effective May 1, 2010, that remove franchise costs from its test year revenue requirements.

IT IS FURTHER ORDERED that North Shore and Peoples Gas shall evaluate the feasibility of uniform service classification numbering and address this in their next rate cases.

IT IS FURTHER ORDERED that North Shore and Peoples Gas shall provide with their compliance filings the Rider VBA "rate case margins" and "rate case customers" resulting from the approved revenue requirements.

IT IS FURTHER ORDERED that North Shore and Peoples Gas shall each annually prepare a report on their rates of return and the effect on that return of Rider VBA and submit it to the Commission and Staff at the same time they file petitions seeking initiation of an annual reconciliation proceeding to determine the accuracy of the Rider VBA Reconciliation Adjustment.

IT IS FURTHER ORDERED that North Shore and Peoples Gas shall revise their transportation tariffs to describe the terms and conditions of the Evening Nomination Cycle; describe the current practice related to handling nomination changes required by upstream cuts; include a storage credit based on reduced storage inventory requirements arising from customers and suppliers filling transportation banks; revise the Standby Commodity Charge; and revise the Maximum Daily Quantity definition.

IT IS FURTHER ORDERED that North Shore and Peoples Gas shall work collaboratively with Staff to develop proposals to unbundle their transportation storage services from their standby services.

IT IS FURTHER ORDERED that North Shore and Peoples Gas are directed to allow super-pooling as proposed in their Brief on Exceptions and adopted herein.

IT IS FURTHER ORDERED that Staff is directed to commence the workshops as proposed, and adopted herein, to address the Small Volume Transportation Program.

IT IS FURTHER ORDERED that any motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 21st day of January, 2010.

(SIGNED) MANUEL FLORES